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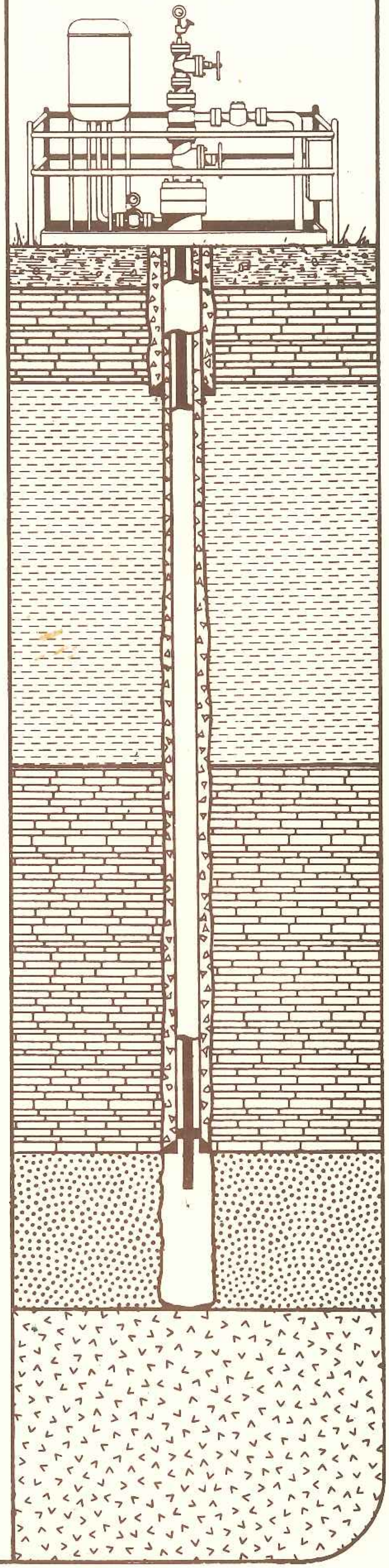
# Evaluation of a Subsurface Waste Injection System near Vickery, Ohio



for

Ohio Environmental Protection Agency

Prepared by

Underground Resource Management, Inc.

Austin, Texas

# EVALUATION OF A SUBSURFACE WASTE INJECTION SYSTEM

# NEAR VICKERY, OHIO

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# INTRODUCTION

This document is a review of commercial waste injection activities at a facility owned and operated by Chemical Waste Management, Inc. (CWM) near Vickery, Ohio. The study was conducted at the request of the Ohio Environmental Protection Agency (OEPA). Due to official and public concern over the safety of waste injection at this site, this study was undertaken in order to assess potential environmental problems that did or could occur as a result of this operation.

Concerns over the safety of using deep wells for waste disposal generally fall into two categories:

1. Operational Procedures. Included are adequacy of well design, operating methods, monitoring method, instrumentation and surveillance, record keeping, integrity testing, and remedial work.

2. Site Suitability. Included are pressure response of the receiving formation, risk of induced seismicity, integrity of confining beds, and rate and direction of natural subsurface migration upon project termination.

This study was conducted to evaluate both past operation of the disposal wells at this site and the potential environmental effects of pressurized injection of fluids into the Mt. Simon Sandstone in this geological terrain. In the course of this investigation, data from a number of sources were reviewed, including files of the Ohio Environmental Protection Agency, the Ohio Department of Natural Resources Divisions of Oil and Gas, Geological Survey, and Water, Chemical Waste Management, Inc., and numerous CWM consultants including: Texas World

Operations, Inc., Golden Strata Services, Inc., Bowser-Morner, Inc., and Golder Associates, Inc. In addition, geological literature and seismic event data were reviewed. Field work included a well integrity testing program, reservoir tests, and inspection of surface equipment, including monitoring instrumentation. This document is intended to serve as a summary of historical operations, a guide to the natural hydrogeological conditions at the site, and an assessment of the anticipated changes to these conditions as a result of injection. In general, operational procedures and hardware considerations are covered in Part A and site suitability and hydrogeology are described in Part B.

This project has resulted in the development of a number of recommendations. The risks associated with different pathways of possible upward migration of waste have been reviewed. We have estimated probable increases in fluid pressure that should be expected in the Mt. Simon Sandstone in the vicinity of the site and the significance of these increases. We have suggested that changes be made in the type and frequency of operational data that CWM submits to the OEPA. Also, we have developed guidelines for official review of this data to help identify significant trends and events.

## EXECUTIVE SUMMARY AND CONCLUSIONS

The disposal wells at the CWM site have been used to inject more than 450 million gallons of wastewater into the subsurface. The permitted disposal zone is the Mt. Simon Sandstone at a depth of 2,800 feet. It is estimated that approximately 8 to 12 percent of the injected volume was injected into two unpermitted saltwater-bearing sandstone formations which occur at depths of approximately 2,500 feet and 2,700 feet. Pressure testing of the well casings revealed that all leaks were located at levels considerably below the deepest fresh-water-bearing formations. The latter are collectively termed the "Big Lime", the base of which is located at a depth of approximately 600 feet.

The reasons that the well casings developed leaks may be due to one or more factors, including the use of explosives to stimulate or clean the wellbore in the Mt. Simon interval, the use of scrapers in the fiberglass casing, and exposure of carbon steel casing to corrosive wastewater.

Detection of leaks near the bottoms of the wells was limited by the operators' ability to accurately measure the volume of fluid in the protective annular oil system. Although the equipment and procedures were adequate to detect any major losses of this oil which could have led to the endangerment of fresh ground water, the minor losses which accompanied leaks near the bottom of the wells produced pressure indications which were not much larger than those caused by changes in waste density, tubing friction, or temperature.

In the case of Well No. 3, data which indicated a major loss of approximately one-half of the annular oil were recorded and reported to

OEPA. All oil below a depth of approximately 1,300 feet was lost; however, this level is 700 feet below the base of the deepest fresh water. Waste exited the well through a hole at a depth of approximately 2,500 feet. The well was operated for a number of months in this condition. In other cases, the operators added oil to the annular systems. Available records do not specifically identify the reasons for the additions. In some cases, oil was repeatedly added over periods of weeks or months. Additions of oil are an indication of oil leakage, and probable waste leakage, through a hole in the casing. A small amount of oil loss is not abnormal; minute quantities of oil may be entrained in the waste stream as it emerges from the end of the injection tubing. However, the quantities of oil that were reportedly added were larger than the few gallons that would be expected to be needed to replace this type of loss.

Recommended requirements for monitoring, inspection, and testing of the injection wells are contained in the body of this report. The company's present well consultants are rebuilding the wells in a manner which allows independent pressurization of the annular fluid system and immediate visual confirmation of fluid losses.

The Mt. Simon Formation is used as a disposal reservoir in several locations in the Great Lakes Region. The locations are widely separated, and the volume of water injected is relatively small compared to the porous volume of the formation. Due to the modest permeability of the formation, relatively high pumping pressures are needed to sustain reasonable rates of injection. The pressure increases in the disposal formation are greatest in the vicinity of a disposal well and decrease rapidly away from a well. As in any disposal well installation, the most sensitive area to be monitored for upward leakage is the wellbore itself. Recommendations for future integrity testing are outlined in the report.

Continued operation of the CWM site appears to offer a very low degree of risk of environmental problems. The area is not seismically active, and no tremors have been detected during the previous operation of the wells, in spite of the fact that sensitive monitoring equipment is located near enough to detect tremors, as small as magnitude 2.0. No faults are known to exist in Sandusky County. The disposal zone is overlain by nearly two thousand feet of low-permeability geologic formations which separate it from the fresh-water bearing "Big Lime".

The Mt. Simon Sandstone is immediately overlain by a carbonate sedimentary rock unit, the Shady Dolomite, which occurs throughout the part of Sandusky County in which substantial pressure increases did and will occur in the Mt. Simon as a result of injection. Microscopic examination of the dolomite shows that microfractures are present, but that they are partially blocked by internal growths of dolomite crystals. The degree of possible interconnection of the open, porous parts of the microfractures cannot be estimated by visual inspection. Laboratory test of plugs cut from cores of the dolomite have generally yielded values of permeability below the lower limit which the equipment employed could measure, which was 0.01 millidarcies (similar tests of Mt. Simon Sandstone yielded permeabilities that were higher by up to 4 orders of magnitude). Some of the tested dolomite plugs may have contained microfractures, but this was not recorded. A value of dolomite permeability as high as approximately 0.002 millidarcies (the value used in a study at Ohio University at Athens) would still slow upward migration to the point where approximately 20 years would be needed for waste or natural brine to migrate completely through the Shady Dolomite and into the Rome Sandstone.

It is difficult to evaluate the possibility that the permeability of the Shady Dolomite in some areas may be greater than 0.002 millidarcies. It would be impractical to attempt to measure the permeability of the dolomite by in-situ testing, and it would probably be inconclusive to measure it by "leaky-aquifer" type analysis of pumping tests of the underlying Mt. Simon Formation. Fortunately, the Rome and Maynardsville Sandstones offer a high degree of protection against upward migration through the Ordovician Black River and Reedsville section to the shallow fresh-water bearing Big Lime. The orders-of-magnitude differences between the permeabilities of the sandstone units and the dolomite units would result in vertical flow in the dolomites and then horizontal flow in the sandstones, precluding upward vertical migration above the Rome Sandstone. The Maynardsville Sandstone offers still another level of protection. In addition, contact of acidic waste with dolomite may cause precipitation of a sealing layer of calcium sulfate (gypsum) when sulfate in the waste combines with calcium liberated from dolomite. In any case, the bulk of any upward-migrating fluid would be native brine. If OEPA feels that extraordinary measures should be taken to provide total assurance that any possible leakage is absorbed by the Rome Sandstone, the agency could consider installation of a monitor well in the Maynardsville Sandstone.

The pressure increases in the Mt. Simon formation occur over a wide area when the wells are in operation. Whenever the wells are turned off, the pressures begin to dissipate. If the wells were operated continuously for a period of years and then turned off, the pressures will decline within an equal period of time or less, to a point where the water levels at the wells will be below land surface. Previous estimates of the volume of waste that the Mt. Simon Sandstone can accept in twenty years of operation appear to be too optimistic. If the flow capacity were 3,000 md/ft and storativity 0.00036, then the Mt. Simon cannot accept a continuous 30 gpm into six wells without reaching the fracturing pressure in less than one year unless there is some upward migration of liquid into the Shady Dolomite. In practice, the wells would be operated until the pressure limit is reached and then shut off until the pressure dissipates.

Records of artificial penetrations in northeastern Sandusky County indicate that all boreholes that were drilled to the top of the Mt. Simon Formation have been plugged. Using the available well logs, there are no indications that faults exist within this area. Due to the fact that elevated pressures will be generated in the Mt. Simon Formation, some official procedure should be adopted by the Division of Oil and Gas whereby drillers of exploratory wells within one or two miles of the site could be warned that higher-than-normal pressures mav be encountered in the Mt. Simon. The pressure increase should have no harmful effect on the ability of the formation to produce oil or gas.

Ideally, the safe operating pressure limit should be based on the pressure required to hydraulically fracture the confining beds. A safe operating pressure based on local hydraulic fracturing data has not been established for the Shady Dolomite. The fracturing pressure of the Mt. Simon Sandstone could be used as a guide to the fracturing pressure of the Shady Dolomite, but local data on the Mt. Simon are also unavailable.

The past operating rules specify a limit of 840 psi surface pressure. This was based on a fracture gradient, which was extrapolated from other formations in other areas of Ohio, of 0.75 psi per foot of depth and a specific gravity of the waste of 1.04. The actual specific gravity of the fluid is closer to 1.07 to 1.08. Using a specific gravity of 1.08 lowers the calculated safe static surface pressure to

790 psi.

Radioactive tracer tests in three of the wells have indicated that no upward migration is occurring at the base of the casing. This confirms that the Shady Dolomite has not been artificially fractured at these wells. Radioactive tracer tests are scheduled to be run in the remaining wells, also. It is recommended that the operating pressure limit be reduced to approximately 790 psi (depending on waste density) in order to observe to the original gradient of 0.75 psi/ft. and to provide a margin of safety until the actual fracture pressure is determined. A factor of safety is provided by the fact that fracture extension pressures are not constant but tend to increase as formation fluid pressure increases due to injection.

Long-term horizontal migration of the slugs of waste within the Mt. Simon sandstone unit will take place at extremely slow rates. Natural circulation will resume after the temporary increase in pressure has dissipated in a relatively few months or years following termination of injection. Flow velocities are expected to be on the order of one-half foot per year. This virtually stagnant movement will be accompanied by dispersion and pH neutralization.

PART A

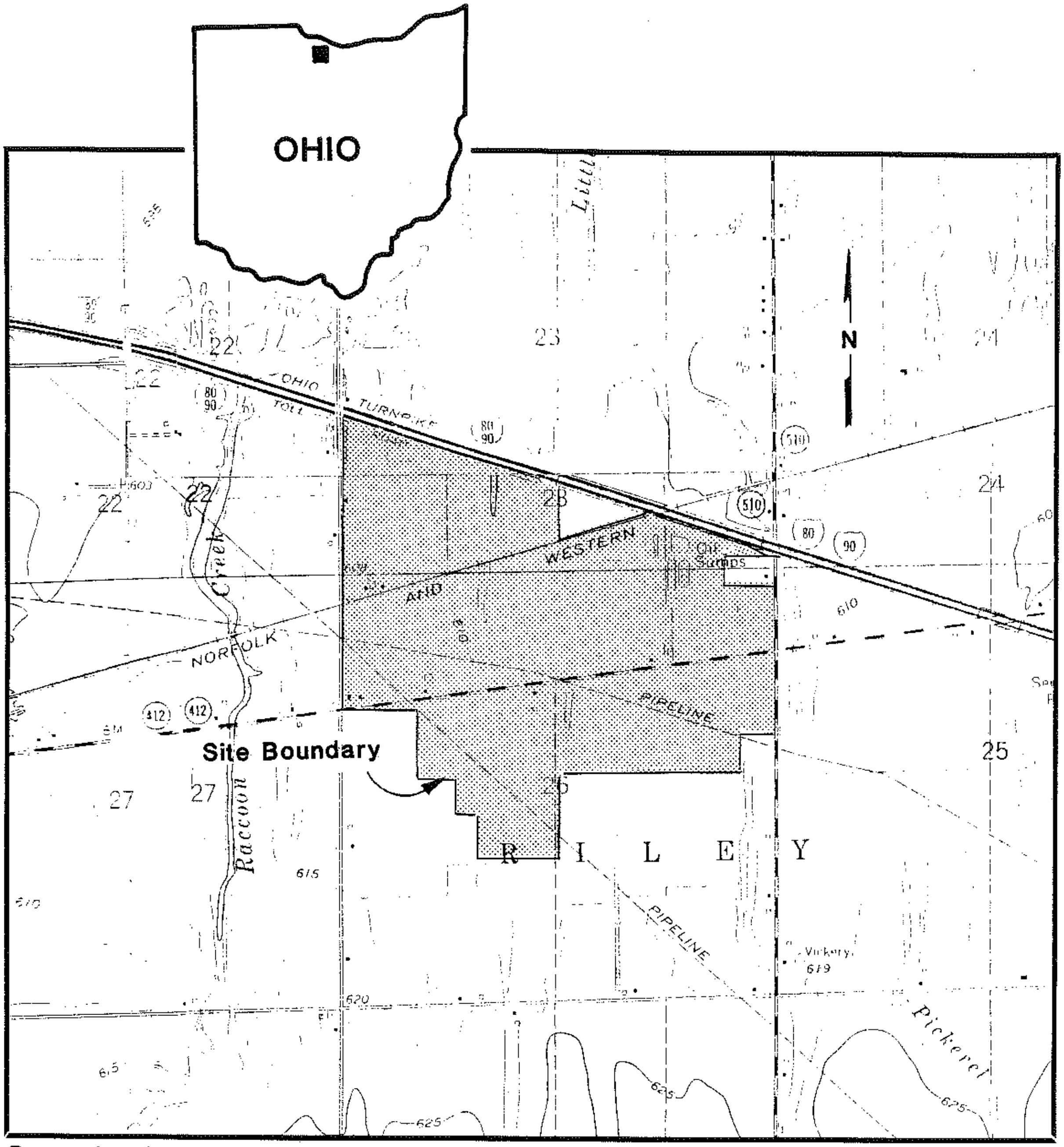
Disposal Wells and Waste Injection

# CHAPTER ONE - WASTE INJECTION AT THE CWM SITE

The waste handling facility near Vickery, Ohio (Figure 1) is operated by Ohio Liquid Disposal, Inc., a subsidiary of Chemical Waste Management, Inc. The site was originally established in 1961 by Don's Waste Oil, which was formed in 1958 to recycle used oil collected from service stations. In 1961, the company began to accept various industrial wastes, such as cutting oils, hydraulic fluids, and some solvents, and stored them in a pond at the Vickery site. In 1964, the company received permission from the Ohio Water Pollution Control Board (predecessor to the Ohio Environmental Protection Agency) to accept chemical process wastes such as pickle liquors from metal-working operations, lime sludges, and off-spec batches of chemical products. Additional ponds were constructed. By the late 1960's, the intake of industrial waste exceeded that of waste oil.

In 1971, the firm was incorporated as Ohio Liquid Disposal, Inc. (OLD). In 1972, the company was issued a permit by the division of Oil and Gas to drill a test hole (Well No. 1) in order to evaluate subsurface conditions for a possible injection well that could be used to dispose of the growing inventory of aqueous waste liquids.

The test hole was drilled to a depth of 2,926 feet or approximately 12 feet into Precambrian igneous basement rocks. The lowermost sedimentary unit, the Mt. Simon Sandstone, was cored and then hydraulically tested in order to measure the flow capacity of the formation. The Mt. Simon Sandstone is approximately 110 feet thick at the location of this well. The long string casing of this well extended to the top of the Mt. Simon Sandstone (2,809 ft.), which was left as an open-hole completion. The long string casing is set inside surface casing, which extends to a depth of 643 feet.



Base taken from U.S.G.S. Vickery & Clyde, Ohio Topographic Quads

Scale
0 2000 4000
Feet

**Figure 1. Project Location Map**

The material that was to be injected at this time had an average analysis as follows:

| | |
|---|---|
| pH | 1.7 |
| TDS | 38,900 mg/L |
| Phenol | 942 mg/L |
| Cl | 5,150 mg/L |
| $SO_4$ | 17,800 mg/L |
| Fe | 8,900 mg/L |
| Zn | 745 mg/L |

An application was submitted for permission to use this well for injection of industrial waste. In September of 1972, the Water Pollution Control Board refused approval for a permit. In this same month, the Division of Oil and Gas refused to issue a permit to convert the well for waste disposal. These decisions were appealed through the judicial system, and in May of 1975, the Court of Appeals in Toledo, Ohio ruled that the permit be issued. In July of 1975, a permit to use Well No. 1 as a waste disposal well was issued by the Division of Oil and Gas. In January 1976, the Division issued permits for three additional wells (Nos. 2, 3, and 4). In April 1976, OLD completed Well No. 1 by drilling out cement left from the installation of the long string casing and installing injection tubing. Waste injection into Well No. 1 was begun on June 7, 1976.

Well No. 2 was completed in November 1976 and waste injection began March 21, 1977.

Wells No. 3 and 4 were completed in November 1976 and waste injection began August 31, 1977.

No waste was injected into Well No. 1 after July, 1979.

Well No. 1A was completed October 1979 to replace Well No. 1, which had suffered corrosion of the long string casing below 1,800 feet after the injection tubing parted at 2,240 feet (OLD letter to OEPA, August 29, 1979). Injection into Well No. 1A began January, 1980.

Well No. 5 was completed in December 1980. Well No. 6 was completed in May 1981. Injection of waste into both wells began in September, 1981.

As of September 1983, approximately 450,000,000 gallons of waste have been injected into disposal wells at the CWM site.

# CHAPTER TWO - INJECTION WELLS

The following descriptions of the physical characteristics and present condition of the waste disposal wells were derived from the files of the OEPA and CWM. Results of integrity testing performed in September through November, 1983, were obtained through on-site observation by URM staff.

The procedures and materials used to construct the disposal wells at the CWM site are described in general terms in the text of this report, while the dimensions and specifications are reported in more detail in Table 1. This information was derived primarily from consultants reports submitted in support of permit applications. The remedial measures and repairs are described in general terms in this chapter. The daily logs kept by drilling engineers during well construction are available for inspection in the files of the OEPA. A general monthly record of pressures and flow rates that have been employed is presented in graphical form in the appropriate places in the text. Daily records of these parameters also exist, but they are voluminous and are not included in this report.

## 2.1 Construction

Seven waste disposal wells have been drilled and completed at the CWM site. One of these wells (No. 1) has been plugged and abandoned. All the wells were completed in the basal sandstone, the Mt. Simon Formation. Surface casing was set in each well to the base of the "Big Lime" formation, at a depth of approximately 600 feet, due to the possibility that this zone may contain fresh water. Each well was completed with a long casing set at the top of the Mt. Simon formation at a depth of approximately 2,800 feet. The Mt. Simon interval has been left uncased in each well, forming an "open hole" completion. Diagrams of

TABLE 1

Well Construction Data

TABLE 1

Well Construction Data

| Category | Well No. 1 |
|---|---|
| Date Drilled | March 1972 |
| Conductor Pipe (Grade/lbs. per foot) | |
| Diam: Pipe O.D./Hole (in.) | |
| Depth (ft.) | |
| Cement | |
| Vol. Used[1] ($ft^3$) | |
| Vol. Annulus ($ft^3$) | |
| Surface Casing | H-40/24 |
| Diam: Pipe O.D./Hole | 8.625/10.75 |
| Depth | 643 |
| Cement | 50-50 Pozmix + Portland, A |
| Vol. Used | 265 |
| Vol. Annulus | 144 |
| Long Casing (Upper) | N-80/? |
| Diam: Pipe O.D./Hole | 5.5/7.875 |
| Depth | 2,809 |
| Cement | Portland, BC |
| Vol. Used | 400[2] |
| Vol. Annulus | 486 |
| Long Casing (Lower) | |
| Diam: Pipe O.D./Hole | |
| Depth | |
| Cement | |
| Vol. Used | |
| Vol. Annulus | |

[1] Sacks of cement times 1.18
[2] Volume apparently too small
[3] Reported volume of Epseal may contain unreported silica flour, actual volume may be larger

Cement Additives: A = $CaCl_2$ Accelerator; B = D-79 Extender; C = D-65 Densifier; D = Silica Flour; E = Bentonite

TABLE 1 (Cont'd)

| Category | Well No. 1A |
| --- | --- |
| Date Drilled | September, 1979 |
| Conductor Pipe (Grade/lbs. per foot) | ?/65 |
| Diam: Pipe O.D./Hole (in.) | 16/18 |
| Depth (ft.) | 43 |
| Cement | Portland, A |
| Vol. Used[1] ($ft^3$) | 147 |
| Vol. Annulus ($ft^3$) | 15.9 |
| Surface Casing | ?/32.75 |
| Diam: Pipe O.D./Hole | 10.75/14.75 |
| Depth | 640 |
| Cement | Portland, A |
| Vol. Used | 590 |
| Vol. Annulus | 356 |
| Long Casing (Upper) | J-55/23 |
| Diam: Pipe O.D./Hole | 7/9.5 |
| Depth | 2341 |
| Cement | Portland |
| Vol. Used | 737 |
| Vol. Annulus | 526 |
| Long Casing (Lower) | Fibercast |
| Diam: Pipe O.D./Hole | 6.625/9.5 |
| Depth | 2341-2802 |
| Cement | Epseal, D |
| Vol. Used | 90.5[3] |
| Vol. Annulus | 116 |

[1] Sacks of cement times 1.18
[2] Volume apparently too small
[3] Reported volume of Epseal may contain unreported silica flour, actual volume may be larger

Cement Additives: A = $CaCl_2$ Accelerator; B = D-79 Extender; C = D-65 Densifier; D = Silica Flour; E = Bentonite

TABLE 1 (Cont'd)

| Category | Well No. 2 |
|---|---|
| Date Drilled | June, 1976 |
| Conductor Pipe (Grade/lbs. per foot) | K-55/75 |
| Diam: Pipe O.D./Hole (in.) | 16/20 |
| Depth (ft.) | 40 |
| Cement | None |
| Vol. Used[1] ($ft^3$) | |
| Vol. Annulus ($ft^3$) | |
| Surface Casing | H-40/40.5 |
| Diam: Pipe O.D./Hole | 10.75/14.75 |
| Depth | 626 |
| Cement | Portland |
| Vol. Used | 500 |
| Vol. Annulus | 348 |
| Long Casing (Upper) | J-55/23 |
| Diam: Pipe O.D./Hole | 7/9.5 |
| Depth | 2362 |
| Cement | Pozmix |
| Vol. Used | 900 |
| Vol. Annulus | 532 |
| Long Casing (Lower) | Fibercast |
| Diam: Pipe O.D./Hole | 6.625/9.5 |
| Depth | 2362-2802 |
| Cement | Epseal, D |
| Vol. Used | 140 |
| Vol. Annulus | 111 |

1 Sacks of cement times 1.18
2 Volume apparently too small
3 Reported volume of Epseal may contain unreported silica flour, actual volume may be larger

Cement Additives:
A = $CaCl_2$ Accelerator
B = D-79 Extender
C = D-65 Densifier
D = Silica Flour
E = Bentonite

TABLE2 1 (Cont'd)

| Category | Well No. 3 |
| --- | --- |
| Date Drilled | June, 1976 |
| Conductor Pipe (Grade/lbs. per foot) | Unknown Type |
| Diam: Pipe O.D./Hole (in.) | 16/? |
| Depth (ft.) | 52 |
| Cement | -- |
| Vol. Used[1] ($ft^3$) | -- |
| Vol. Annulus ($ft^3$) | -- |
| Surface Casing | H-40/40.5 |
| Diam: Pipe O.D./Hole | 10.75/14.75 |
| Depth | 662 |
| Cement | Portland |
| Vol. Used | 500 |
| Vol. Annulus | 333 |
| Long Casing (Upper) | J-55/23 |
| Diam: Pipe O.D./Hole | 7/9.5 |
| Depth | 2358 |
| Cement | Pozmix |
| Vol. Used | 900 |
| Vol. Annulus | 531 |
| Long Casing (Lower) | Fibercast |
| Diam: Pipe O.D./Hole | 6.625/9 |
| Depth | 2358-2772 |
| Cement | Epseal, D |
| Vol. Used | 142 |
| Vol. Annulus | 104 |

[1] Sacks of cement times 1.18
[2] Volume apparently too small
[3] Reported volume of Epseal may contain unreported silica flour, actual volume may be larger
[4] Hole was 13.75 in diameter to 435 ft.

Cement Additives: A = $CaCl_2$ Accelerator; B = D-79 Extender; C = D-65 Densifier; D = Silica Flour; E = Bentonite

TABLE 1 (Cont'd)

| Category | Well No. 4 |
|---|---|
| Date Drilled | July, 1976 |
| Conductor Pipe (Grade/lbs. per foot) | Unknown Type |
| Diam: Pipe O.D./Hole (in.) | Unknown |
| Depth (ft.) | Unknown |
| Cement | |
| Vol. Used[1] ($ft^3$) | |
| Vol. Annulus ($ft^3$) | |
| Surface Casing | H-40/40.5 |
| Diam: Pipe O.D./Hole | 10.75/14.75 |
| Depth | 639 |
| Cement | Portland, A |
| Vol. Used | 500 |
| Vol. Annulus | 355 |
| Long Casing (Upper) | K-55/? |
| Diam: Pipe O.D./Hole | 7/9.5 |
| Depth | 2377 |
| Cement | Pozmix |
| Vol. Used | 900 |
| Vol. Annulus | 537 |
| Long Casing (Lower) | Fibercast |
| Diam: Pipe O.D./Hole | 6.625/9 |
| Depth | 2377-2794 |
| Cement | Epseal, D |
| Vol. Used | 142 |
| Vol. Annulus | 105 |

1 Sacks of cement times 1.18
2 Volume apparently too small
3 Reported volume of Epseal may contain unreported silica flour, actual volume may be larger

Cement Additives: A = $CaCl_2$ Accelerator; B = D-79 Extender; C = D-65 Densifier; D = Silica Flour; E = Bentonite

TABLE 1 (Cont'd)

| Category | Well No. 5 |
|---|---|
| Date Drilled | November, 1980 |
| Conductor Pipe (Grade/lbs. per foot) | ?/62 |
| Diam: Pipe O.D./Hole (in.) | 16/? |
| Depth (ft.) | 56 |
| Cement | Portland, A |
| Vol. Used[1] ($ft^3$) | 88.5 |
| Vol. Annulus ($ft^3$) | ? |
| Surface Casing | ?/45.5 |
| Diam: Pipe O.D./Hole | 10.75/14.75 |
| Depth | 645 |
| Cement | Portland, A |
| Vol. Used | 590 |
| Vol. Annulus | 358 |
| Long Casing (Upper) | K-55/23 |
| Diam: Pipe O.D./Hole | 7/9.5 |
| Depth | 2719 |
| Cement | Pozmix, E |
| Vol. Used | 737[5] |
| Vol. Annulus | 611 |
| Long Casing (Lower) | Inconel 625 |
| Diam: Pipe O.D./Hole | 7/9.5 |
| Depth | 2719-2781 |
| Cement | Epseal, D |
| Vol. Used | 140 |
| Vol. Annulus | 13.5 |

[1] Sacks of cement times 1.18
[2] Volume apparently too small
[3] Reported volume of Epseal may contain unreported silica flour, actual volume may be larger
[5] Cement set too quickly upper 1,300 feet not cemented until later, during completion

Cement Additives: A = $CaCl_2$ Accelerator; B = D-79 Extender; C = D-65 Densifier; D = Silica Flour; E = Bentonite

TABLE 1 (Cont'd)

| Category | Well No. 6 |
|---|---|
| Date Drilled | November, 1980 |
| Conductor Pipe (Grade/lbs. per foot) | ------- |
| Diam: Pipe O.D./Hole (in.) | 16/? |
| Depth (ft.) | 51 |
| Cement | Portland, A |
| Vol. Used[1] ($ft^3$) | 118 |
| Vol. Annulus ($ft^3$) | ? |
| Surface Casing | ?/45.5 |
| Diam: Pipe O.D./Hole | 10.75/14.75 |
| Depth | 642 |
| Cement | Portland, A |
| Vol. Used | 590 |
| Vol. Annulus | 357 |
| Long Casing (Upper) | K-55/23 |
| Diam: Pipe O.D./Hole | 7/9.5 |
| Depth | 2727 |
| Cement | Pozmix |
| Vol. Used | 737 |
| Vol. Annulus | 614 |
| Long Casing (Lower) | Inconel 625 |
| Diam: Pipe O.D./Hole | 7/9.5 |
| Depth | 2727-2788 |
| Cement | Epseal, D |
| Vol. Used | 138 |
| Vol. Annulus | 34 |

1 Sacks of cement times 1.18
2 Volume apparently too small
3 Reported volume of Epseal may contain unreported silica flour, actual volume may be larger

Cement Additives:
A = $CaCl_2$ Accelerator
B = D-79 Extender
C = D-65 Densifier
D = Silica Flour
E = Bentonite

each well showing locations of geologic formation tops are presented in this chapter.

The long casings are composed of different materials in each well (Table 1). In Well No. 1, the long casing is made of carbon steel for its entire length. Wells 1A, 2, 3, and 4 have casings made of approximately 400 feet of fiberglass at the lower end, and the upper length is carbon steel. The bottom 60 feet of casing in Wells 5 and 6 is made of Inconel 625 and the upper part is carbon steel. The fiberglass and Inconel casings are cemented in place with a slurry of Epseal resin and silica flour, and the steel upper casings are cemented with either regular Portland API Class A cement or with Pozmix, or with a mixture of the two cements (Table 1). The two-stage cementing jobs are accomplished by installing a cement diverter collar (DV tool) at the point where the two casings of different materials are joined together.

Wells 1, 1A, 2, 3 and 4 were originally completed with fibercast injection tubing suspended inside the long casing. The space between tubing and casing was filled with diesel oil or fuel oil. The tubing strings were equipped with electrical contacts attached near the lower end. One pair of contacts was typically 300 feet above the other pair. The purpose of the contacts was to measure the conductivity of the adjacent fluid. Since oil is much less conductive than injected waste or formation brine, the position of the contact or interface between the oil and water should be determinable by this method. For example, a sharp increase in conductivity measured at the upper pair of contacts would signal a rise in the oil/water contact, indicating a loss of oil due to a leak in the long casing. This system did not prove to be entirely satisfactory (See next section). Packers were installed at the base of the tubing in Wells 5 and 6.

## 2.2 Operational History

The operational history has been derived from data, logs, and written reports compiled by CWM and consultants. General well performance has been reviewed based on pressure and flow rate data recorded during normal operations. The results of treatments, inspections, and repairs that have been performed on these wells and described below are reflected to some extent in the changes of well injectivity that are evident in the operational data. These data also suggest approximate times and amounts of leakage, occurrence of wellbore damage due to plugging of the formation, and improvements of well performance that may be due to either stimulation treatments or normal acid disposal.

Estimation of well condition is approximate due to the quality and type of existing data. Simultaneous readings of injection pressure and flow rate were not made during most of the early operational period. Daily total gallonage figures recorded during each operating month have been reviewed, and a representative flow rate for each month has been derived by selecting the full 24-hour operating day that appears to most adequately represent well behavior during that month, and dividing the total gallons by the number of minutes in a day. This monthly "apparent representative injection rate", in gallons per minute, has been plotted on the operating summary charts presented in this chapter. Also shown are the "representative" pressures on the injection tubing and the casing (annulus) for that month. Pressures were read and recorded by the well operators every two hours during much of the past operating period (they are now continuously recorded), and then the pressure that was recorded at, for example, noon on each day of the month was posted to the records used to derive the flow rates mentioned above. Since the noon reading may not reflect the actual pressure that was used to achieve the representative flow rate, the noon readings of the other days in the month and the corresponding daily gallonages were checked to make sure the selected reading was reasonably representative.

The data shown on the operating summary charts should be considered to be only approximations for additional reasons. First, the accuracy of gauges and meters is generally unknown. Second, two wells often operated through a single flow meter, and during these periods, the flow rates represent the total rate divided by two. Performance of individual wells is not easily estimated for these periods unless spot checks of individual flow rates were made and noted in the original records.

2.2.1 Well No. 1: Injection of waste into Well No. 1 began on June 7, 1976. The initial flow rate was approximately 42 gpm with a wellhead pressure (WHP) of 590 psi. Records of representative for each injection pressure, annulus pressure, and flow rate for each month have been plotted on Figure 2. A construction diagram is shown on Figure 3. By the end of June, the injection pressure and apparent flow rate were 650 psi and 41.5 gpm, respectively.

The injection pressure continued to increase in the following months, reaching 760 psi at a flow rate of 35 gpm in October 1976. A slight increase in conductivity apparently prompted the operators to add oil to the annulus during this month. The conductivity dropped from "3.5" to "0" after the addition of the oil. The units of these measurements are not indicated.

In November 1976, 200 gallons of oil was again added to the annulus, which lowered the conductivity once more from "3.5" to "0". The formation was acidized, which resulted in a lowering of the injection pressure from 720 psi to 660 psi at a flow rate of 33 gpm.

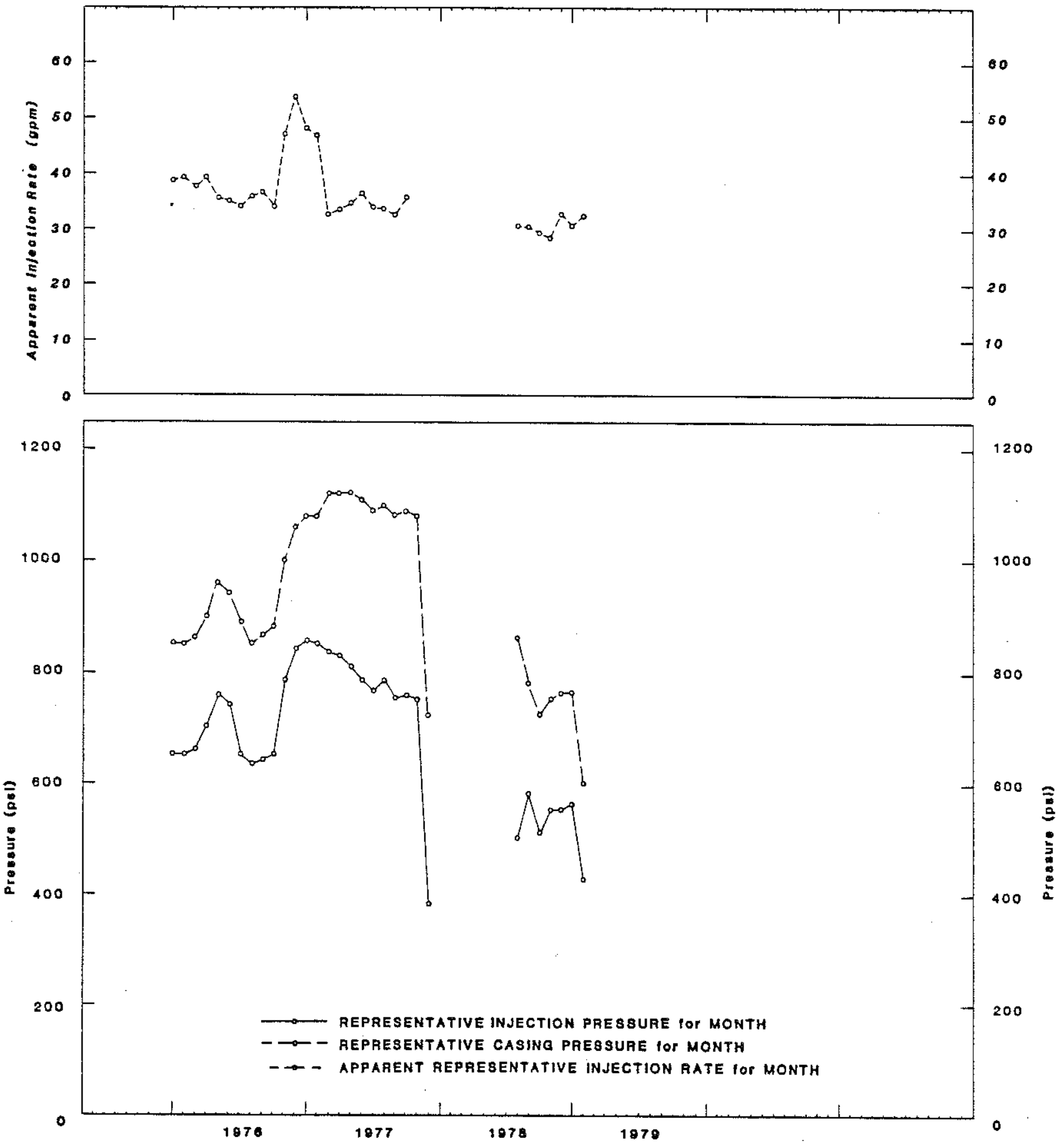



**Figure 2. Summary of Operating History, Well No. 1**

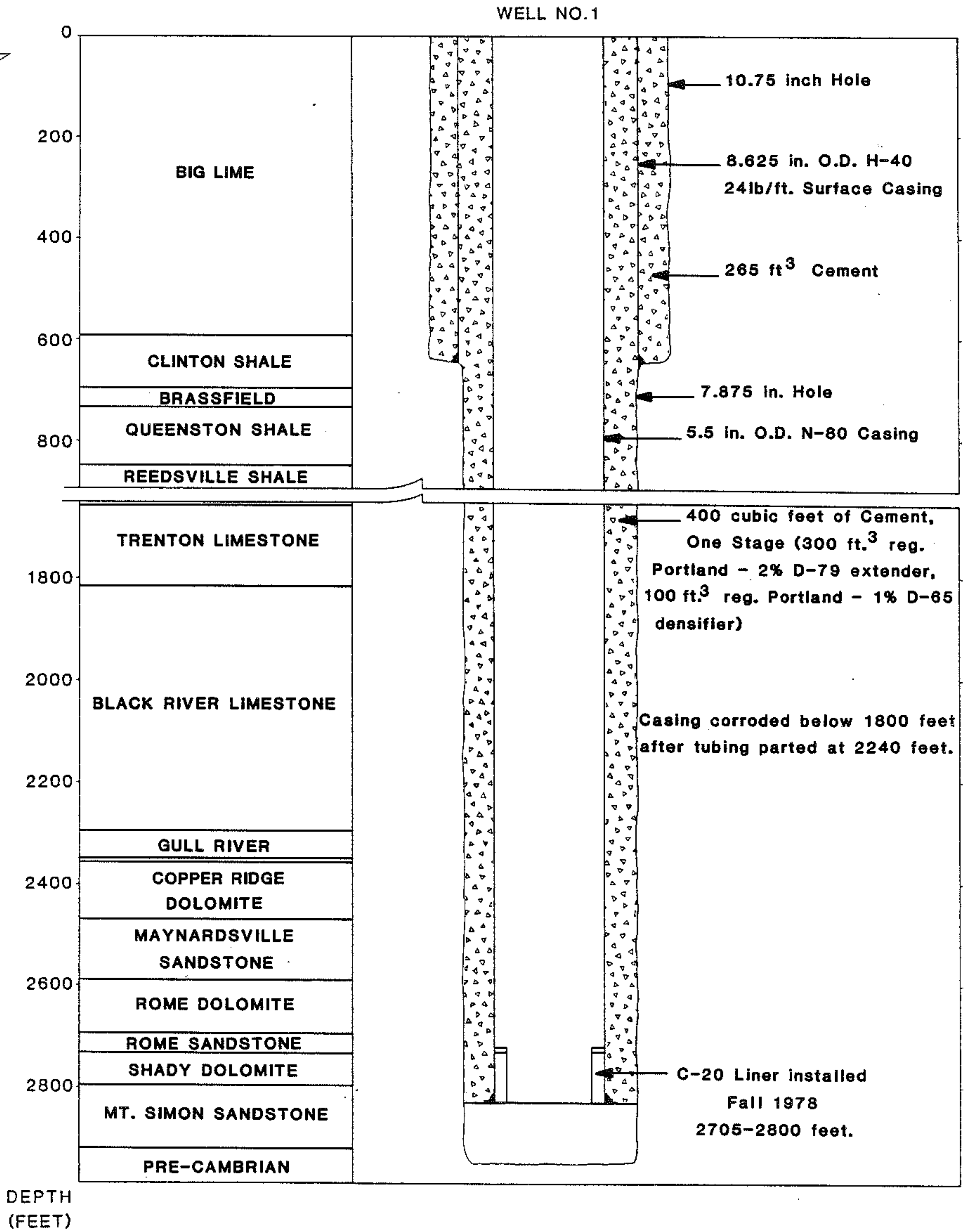



Figure 3. Stratigraphy and Completion Diagram, Well No. 1

In February 1977, Well No. 2 was placed in service, and total flow into the two-well system was reported after that time. The flow rates shown in Figures 2 and 4 represent this total apparent rate divided by two.

In March 1977, the injection pressure and flow rate into the two wells was increased to approximately 780 psi and 96 gpm (48 gpm assumed average, each well), respectively. However, the pressure necessary to maintain this rate soon rose to the permitted maximum (840 psi), and the flow rate had to be reduced in May, 1977.

On July 13, the two wells were acidized and allowed to flow back in order to clean the formation face, but by July 15 the pressure again rose above 800 psi. By August 1977, the rate had been reduced to an average of approximately 32 gpm per well, at an injection pressure of approximately 800 psi. Over 400,000 gallons of fresh water was injected into the two-well system to attempt to dissolve possible water-soluble precipitate at the formation face.

The injection rate into the two wells remained almost unchanged (apparent avg. 34 gpm each) through early 1978, while the injection pressure gradually declined from 850 psi to 730 psi. A gradual decline of this type may indicate wellbore improvement by action of the acid waste on the formation near the well. It may also indicate development of leaks in the casing.

Company records indicate that in May 1978, a casing inspection log revealed that the bottom 35 feet of the steel casing in Well No. 1 (Well No. 1 had all steel casing) had suffered corrosion (letter OLD to OEPA July 14, 1978). A 4" O.D. Carpenter-20 (a corrosion-resistant alloy) liner was cemented in place in the interval from 2,705 to 2,800 feet.

The well was returned to service in January 1979.

The injection rate into No. 1 at this time may have been relatively low. Well No. 2 had been injecting approximately 60 gpm while Well No. 1 was being repaired. Before repair of No. 1 was initiated, the combined two-well system had accepted only approximately 60 gpm. When Well No. 1 was returned to service, the combined flow rate was only approximately 60 gpm.

In July 1979, the difference in pressure between tubing and annulus in Well No. 1 declined to below normal levels (approximately 200 to 220 psi). This pressure difference is a measure of the amount of oil in the annulus, and thus it is an indicator of possible leakage in the casing or tubing if the difference is abnormally low (see Sections 2.5 and 3.2). The tubing was removed from the well and found to be parted at 2,240 feet. A casing inspection log revealed that the casing had been subjected to corrosion from approximately 1,800 feet to the top of the C-20 liner. (Letter OLD to OEPA August 29, 1979).

Well No. 1 was plugged and abandoned in July 1980. The well was killed with ammonium sulfate brine, according to the engineer's report. A string of steel 2-3/8 inch diameter tubing was run to 2,800 feet. The well was circulated clean of fill down to 2,932 feet. Diesel fuel (933 gal.) was pumped down the tubing followed by 408 gallons of Epseal mixed with 20% silica flour. This was followed by 200 gallons of diesel fuel and 250 gallons of water. The tubing was pulled up to 2,766 feet to place the Epseal plug across the disposal formation (open-hole interval). The plug was allowed to set up overnight, and the top of the plug was tagged at 2,766 feet the next day. Explosives were used to create a cavity at 2,740 to 2,760. Open-ended tubing was run to 2,747 feet, and 45 barrels of drilling mud were pumped down the tubing followed by 100 sacks of Class A cement, followed by 94 $ft^3$ of drilling mud. Another cavity was created with explosives at 770 to 780 ft. This cavity was cemented with 100 sacks of Class A cement, and the casing was filled with cement to the surface.

2.2.2 Well No. 2: During initial tests, this well accepted fresh water at a rate of 50 gpm at an injection pressure of 380 psi. Injection of waste into Well No. 2 started in March 1977. Representative injection pressure, annulus pressure, and flow rate for each month are shown on Figure 4. A construction diagram is shown on Figure 5. Since Wells No. 1 (later 1A) and No. 2 received waste through a common flow meter until August 1980, the actual injectivity of Well No. 2 is uncertain except in periods when Well No. 1 was out of service. The combined system of Wells No. 1 and No. 2 was accepting 130,000-155,000 gallons per day, or an apparent 90-107 gpm at 840 psi, in May 1977.

The injection pressure of the combined wells increased to the permitted maximum (840 psi) in late May 1977, and the flow rate was reduced, as previously mentioned in Section 2.2.1. The wells were acid treated and backflushed in July 1977, but the resulting reduction in injection pressure lasted only two days. In August, over 400,000 gallons of fresh water was injected into the two wells to dissolve any water-soluble precipitate at the formation face.

The injection rate into the two wells remained almost unchanged (apparent avg. 34 gpm each) through early 1978, while the injection pressure gradually declined from 850 psi to 730 psi. In May 1978, Well No. 1 was shut down for repairs, and during the following eight months, injection rates of over 60 gpm were recorded with only Well No. 2 operating.

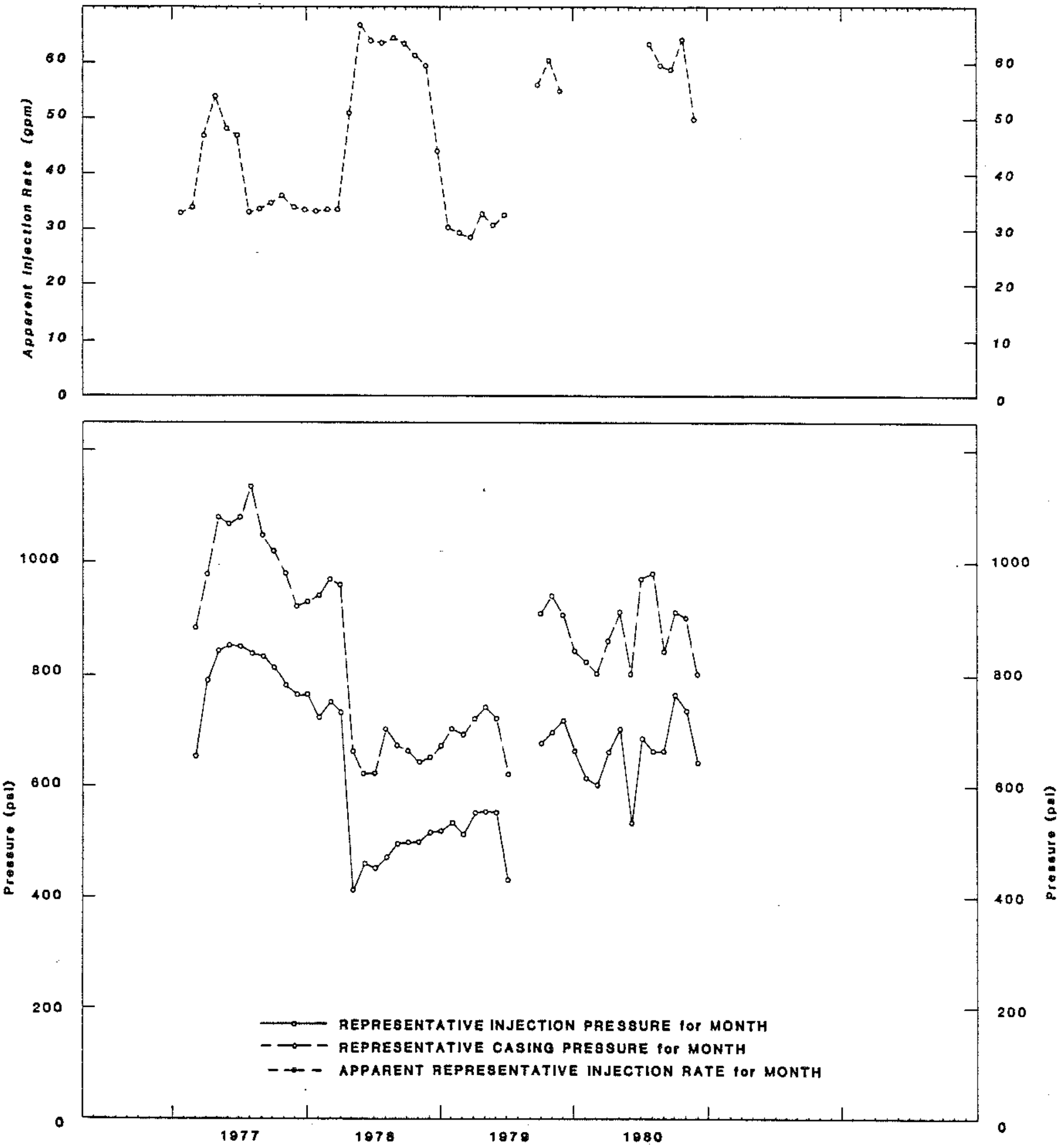



**Figure 4. Summary of Operating History, Well No. 2**

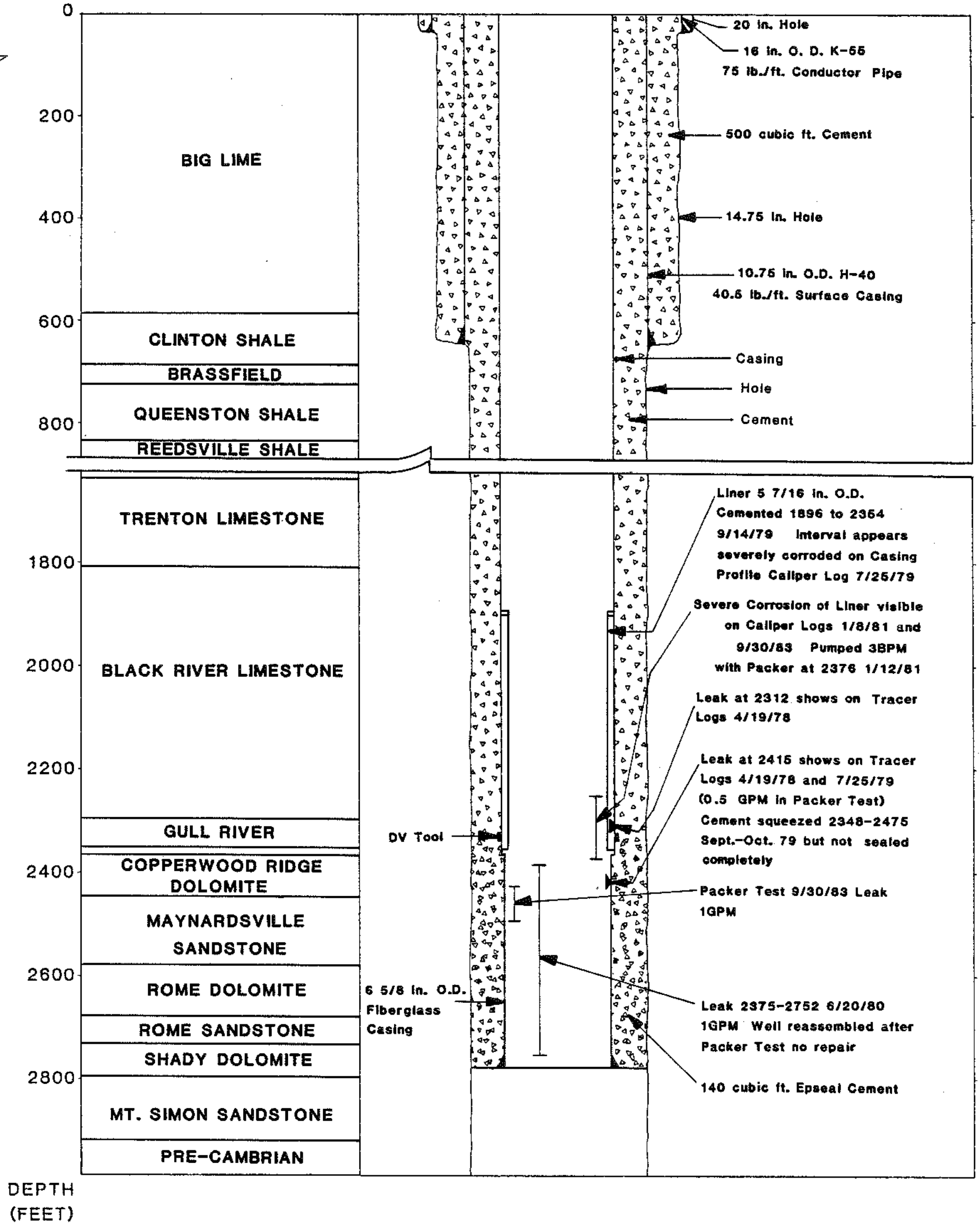



Figure 5. Stratigraphy and Completion Diagram, Well No. 2

During April 1978, a radioactive tracer survey was run in Well No. 2. This log ws interpreted as a confirmation of the absence of leakage around the base of the long string casing. However, reexamination of this log for this report indicates a significant increase in radioactivity at 2,312 and 2,414 feet after the tracer was injected.

Well No. 1 was returned to service in January 1979. The injection rate into No. 1 may have been low since the combined flow rate for Wells No. 1 and 2 was reported to be approximately 60 gpm, whereas Well No. 2 had been injecting at 60 gpm alone. Also, Well No. 2 reportedly accepted 60 gpm alone after Well No. 1 was taken out of service (permanently) in July 1979.

Later in July 1979, Well No. 2 was shut down for testing. A casing inspection log run July 25, 1979 reportedly indicated corrosion from 2,112 to 2,378 feet, near the bottom of the steel part of the casing. Two radioactive tracer surveys (July 18 and July 25) reportedly indicated that there was not a leak in this interval. Upon reexamination, the quality of those logs was found to be insufficient to reconfirm the leakage at 2,312 feet indicated by the tracer log in April 1978, possibly due to apparent low setting of the gain control (July 25 log) and failure to log the interval 2,300 to 2,600 (July 25). The log of July 18, however, shows an increase of radioactivity at 2,419 feet. A 5-9/16" O.D. steel liner was installed in the well in the depth interval 1,903 to 2,364 feet on September 14, 1979 (Letter OLD to OEPA, October 10, 1979). Following this procedure, the lower fiberglass casing was tested with tubing and packer, and a leak in the casing was discovered in the depth interval 2,431 to 2,461. The leak rate is estimated to be approximately 0.5-1.0 gpm (pressure loss 700 psi to 150 psi in 15 minutes; 8 gallons required to raise pressure from 150 to 700 psi. This repressuring is equivalent to a system compressibility of approximately

$4.4 \times 10^{-6}$ $psi^{-1}$: Eight gallons for 550 psi increase, or 0.0145 gal/psi, with an annular volume of approximately 3,300 gallons.) Several unsuccessful attempts were made to repair this leak in the fiberglass casing by squeezing cement. Tubing equipped with a conductivity cell at a depth of 2,401 feet was installed in the well, and the well was returned to service in October 1979.

In the 12 months following this procedure, oil was reportedly added to the annulus of Well No. 2 on several occasions. During this period, Well No. 1 was plugged, abandoned, and replaced with Well No. 1A. Well No. 2 was taken out of service for inspection in June of 1980. A caliper log reportedly indicated that the liner installed the previous year had not suffered appreciable corrosion. The liner and upper steel casing was tested with tubing and packer from 2,375 to the surface and was reported to be in good condition. The depth interval from 2,375 to 2,752 feet lost pressure from 700 psi to 250 psi (time unknown) in a static test. The depth interval from 2,502 to 2,752 also lost pressure, apparently at a lower rate. The depth interval from 2,483 to 2,752 lost pressure from 700 psi to 300 psi in 5 minutes, and it took addition of approximately 3 gallons to bring pressure back up to 700 psi. The leak rate was therefore less than 1 gpm in the latter interval. The well was treated with a caustic solution and returned to service.

In August 1980, separate flow meters were installed at Wells No. 1A and No. 2. Well No. 2 had a recorded apparent injection rate of approximately 60 gpm. The differential pressure between tubing and casing declined to approximately 150 psi during the next several months.

Well No. 2 was taken out of service in December 1980. A caliper log run on January 8, 1981 indicated that the liner had suffered "severe corrosion" from 2,250 to 2,370 feet. Tubing and a packer were run in the hole and the packer was set at 2,376 feet. The casing was pressurized to 90 psi and the flow rate was reported to be "3 barrels per minute". The packer was moved to 2,225 feet, and in this position, the casing reportedly held 1,000 psi for 10 minutes. (OEPA notified of leak March 6, 1981)

Well No. 2 has not been in operation since December 1980.

2.2.3 Well No. 1A: Well No. 1A was drilled in 1979 as a replacement for Well No. 1. The injection zone was treated with 15% HCl in October, 1979, and after this treatment, the flow rate was reportedly 45 gpm at a "reasonable" pressure. Approximately three million gallons of fresh water were injected as a buffer at a rate of 30-35 gpm at 550-600 psi after the acid treatment (Consultant's letter to OLD April 10, 1981). Injection of waste began on January 1, 1980. Wells No. 1A and 2 pumped through a common flow meter until August, 1980. For this reason and for the reasons mentioned at the beginning of Section 2.1, some details of the early performance of Well No. 1A are uncertain. Representative injection pressure, annulus pressure, and flow rate for each month are shown on Figure 6. A construction diagram is shown on Figure 7.

The conductivity cells in Well 1A apparently have been unreliable as indicators of the level of the oil-water interface in the long casing. Changes in measured conductivity may have been the reason for the additions of oil (February, 1980; October, 1980; March, 1981) even though pressure differentials between casing and tubing evidently had been "normal" at those times. On the other hand, gradual declines in apparent pressure differential (250 to 200 psi, April, 1980) were not accompanied by significant changes in conductivity of either one of the cells. The conductivity has remained high after workovers in which the

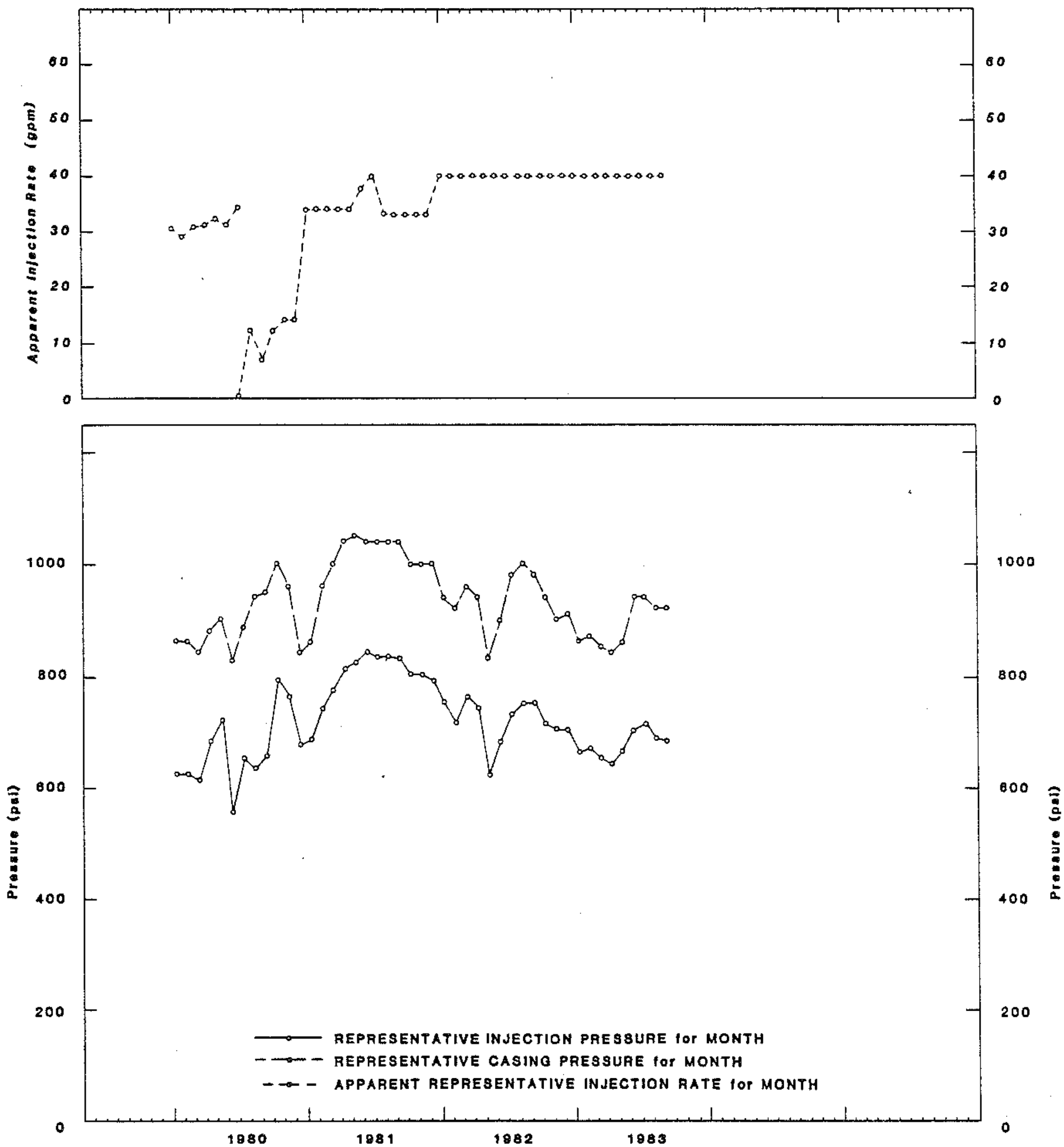



**Figure 6. Summary of Operating History, Well No. 1A**

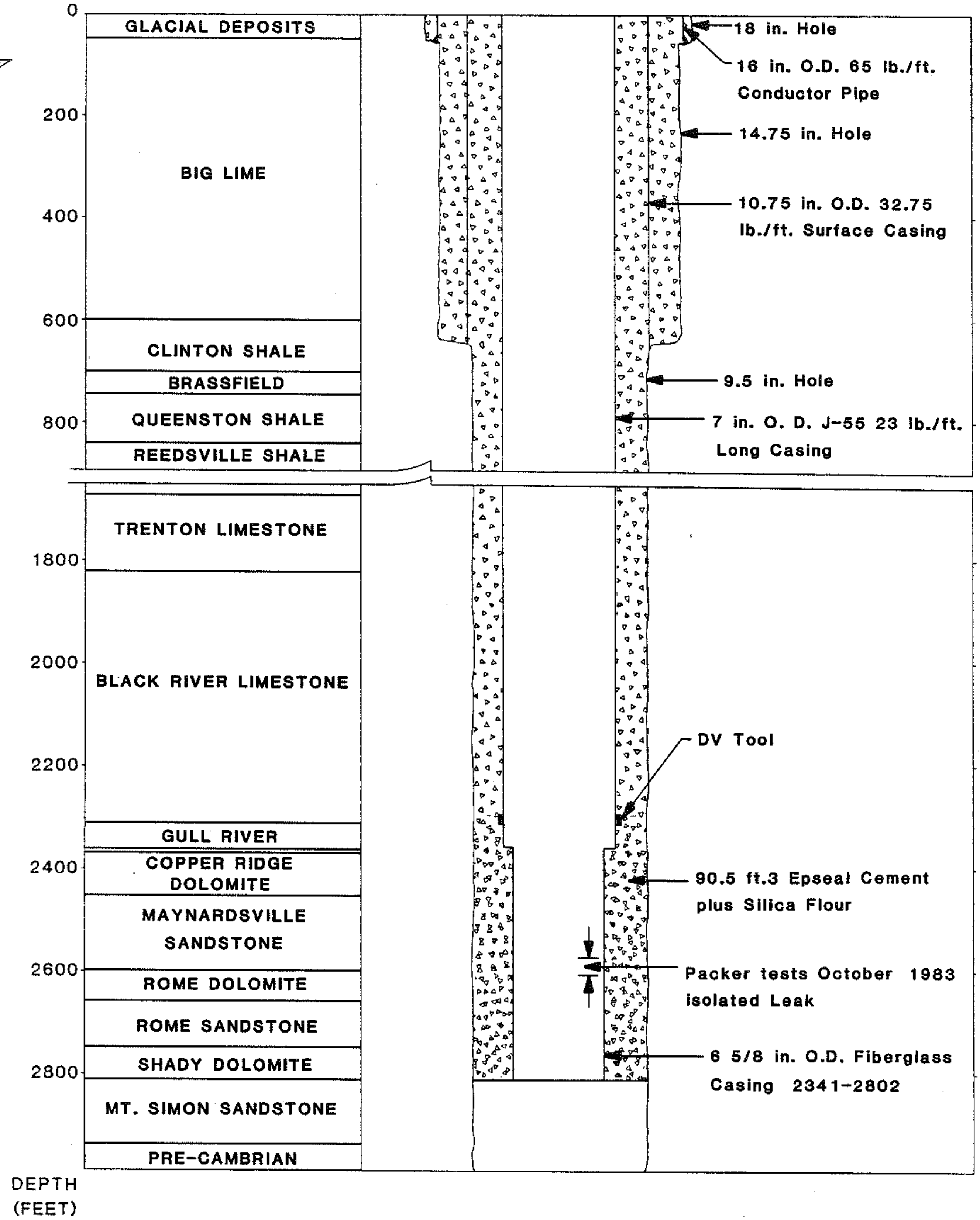



Figure 7. Stratigraphy and Completion Diagram, Well No. 1A

oil was completely replaced (August, 1980). The general topic of monitoring is discussed in more detail in Chapter 4.

In June, 1980, the well was closed in due to a reported injection rate of only 2 gpm. The well was treated with both caustic and acid solutions and circulated through tubing to clean out solids. A caliper log was run in the disposal zone, and a radioactive tracer test was performed. Examination of this log indicates that fluid was flowing only into the Mt. Simon Formation. The fluid reportedly was injected at 640 psi at 60 gpm in this test. According to CWM records, the well was "stimulated at 2,830 to 2,840 feet" during this workover. It is not known what procedures were involved in this "stimulation".

Well No. 1A was equipped with a separate flow meter after this workover in August, 1980. The flow rate was reported to be only 12 gpm, falling to 5 gpm after three days. The rate in November, 1980 was reportedly only 9 gpm. The well was then cleaned with a caustic solution and injection resumed at a reported 660 psi at 14 gpm. After two weeks of inactivity in late 1980, during which Well No. 2 was treated, Well No. 1A restarted at 34 gpm at 660 psi. The reason for the increase is not known, as no workover procedures appear in the records.

Injection into Well No. 1A from early 1981 to the present is practically without incident, except for an apparent increase in flow rate from 34 to 40 gpm and a decrease in injection pressure from 790 to 680 psi in January, 1982. Well No. 2 was not operating at this time. Possible causes for sudden increases in injectivity include: increase in specific gravity of waste stream, dissolution of solids at the face of the injection zone, or leakage through the casing into a different zone. The results of integrity testing of this well in October, 1983 are described in Section 2.3.1.

2.2.4 Well No. 3: Injection of fresh water buffer into Well No. 3 began in June, 1977. Initial tests showed that the well would accept 50 gpm at 650 psi. Wells No. 3 and 4 were operated with a single injection pump (The wells had separate flow meters initially, but due to meter inaccuracy, only the combined two-well flow, as recorded on a magnetic flow meter on the upstream side of the injection pump, was reported after December, 1977). A total of 2.53 million gallons of fresh water were injected into the two wells, and an estimated 60% went to Well No. 3, with the balance entering Well No. 4, according to operator's notes. Injection of waste acid began August 29. A summary of the operating history of Well No. 3 is shown on Figure 8. A construction diagram is shown on Figure 9.

The system was affected initially by problems with inaccurate pressure sensors and flow meters, leaking injection lines, and poor injectivity. The injection pressure necessary to deliver a combined 80 gpm rose to 830-840 psi. For a two-week period, the wells were operated daily until this pressure level was reached, then shut down until the next morning. After cleaning Well No. 4, the system was returned to injection, but Well No. 4 apparently received little of the flow due to continuing plugging problems.

In February and again in March, 1978, oil was reportedly added to the casing of Well No. 3. A total of 1,120 gallons was reportedly added. This would equal nearly half of the total volume of oil that should have been in place. Some of the oil may have been pushed out into the disposal formation. The pressure differential before adding oil was recorded as approximately 150 psi, and the additional oil did not significantly raise this differential. Well No. 3 was shut down at the end of March for inspection.

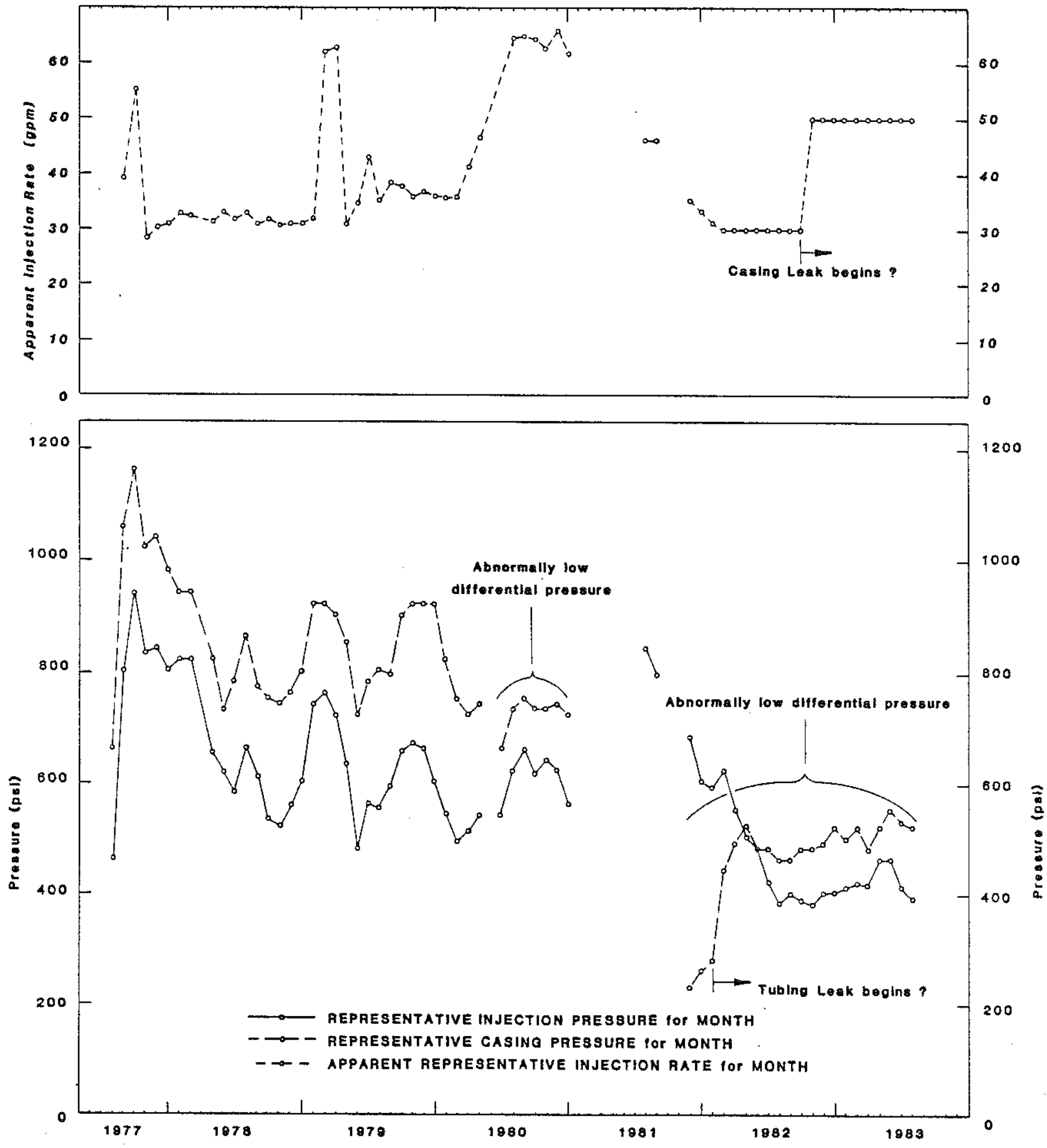



Figure 8. Summary of Operating History, Well No. 3

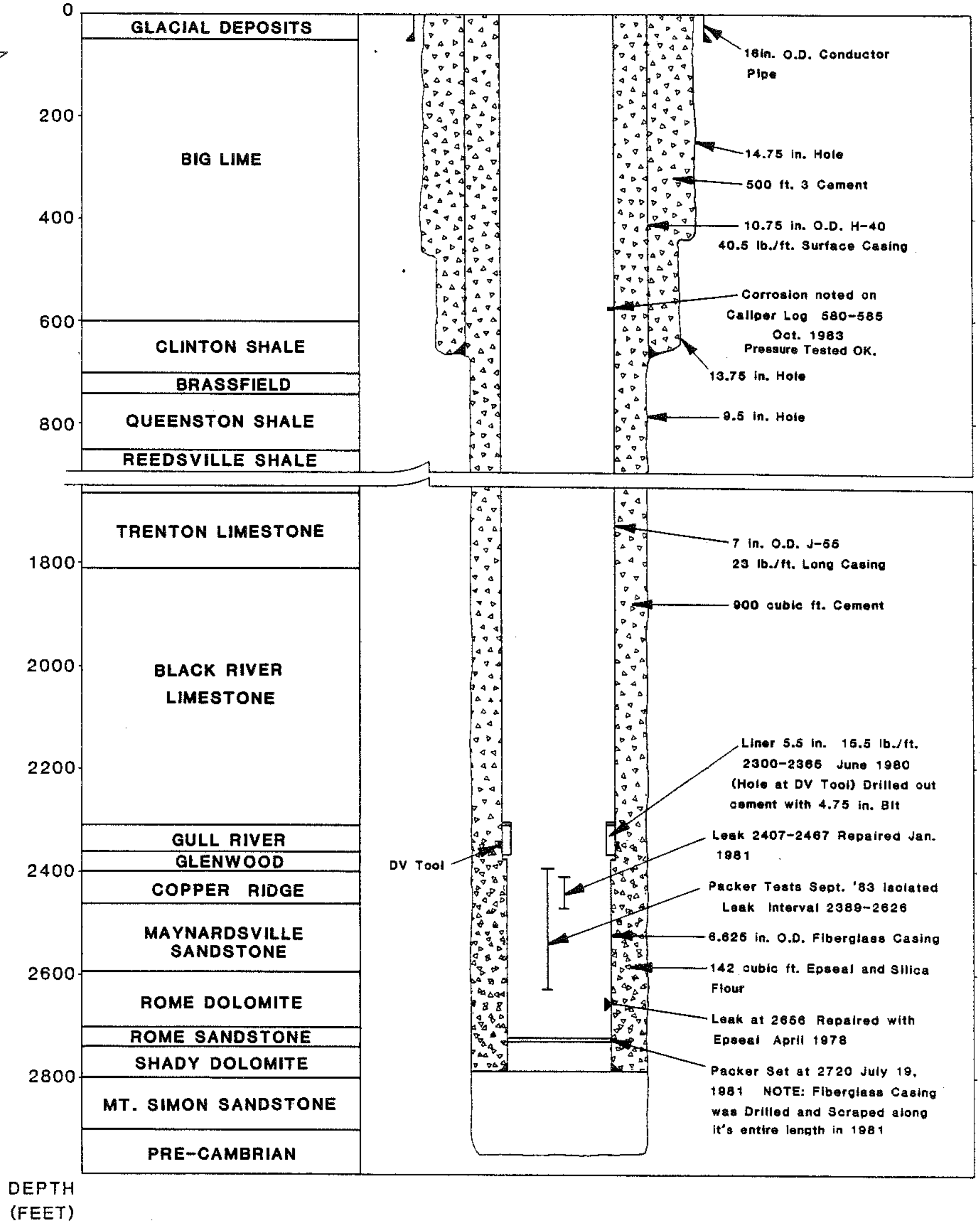



Figure 9. Stratigraphy and Completion Diagram, Well No. 3

The tubing was removed from the well, and a radioactive tracer survey was run. Increases in radioactivity were noted at depths of 2,617 feet and 2,648 to 2,656 feet. This zone was squeezed with Epseal cement and the well was returned to service. Flow rates in the following months were approximately 40-45 gpm at 600-650 psi.

In June, 1978, oil was added to the casing of either Well No. 3 or Well No. 4, but records are not clear. Pressure differential was 180 psi and 120 psi at Wells No. 3 and No. 4, respectively, according to operating logs. Neither differential increased after the reported addition of oil.

The increase in injection pressure noted in early 1979 (Figure 8) is most likely due to Well No. 4 being taken out of service. The flow rate from the (positive displacement) pump continued unchanged at approximately 60 gpm, which, since Well No. 4 was not in operation, apparently caused the flow rate into Well No. 3 to increase from an estimated 40-50 gpm up to the full 60 gpm.

In January, 1980, oil was added to the casing of Well No. 3 due to apparent increase in conductivity. Addition of oil did not lower the reported conductivity. Reported differential pressure between the casing and tubing was approximately 200-210 psi, both before and after addition of the oil.

Well No. 3 was shut down at the end of May, 1980 for inspection. On May 27 the casing pressure was recorded to be 740 psi (recorder) or 660 psi (gauge) and the tubing pressure was recorded as 530 psi (recorder) or 520 psi (gauge). The difference in gauge pressures was subnormal.

The tubing was removed and found to be parted at a split collar at 2,388 feet from the top of the tubing. A caliper log was run that showed corrosion from 2,341 feet to 2,351 feet, and a possible hole at the DV collar at 2,341 feet. This corresponds to a geologic horizon approximately 15 feet above the Knox Unconformity, which is an erosional surface at the top of the Copper Ridge Formation (Knox Formation). A 5.5 inch O.D. steel liner was installed in the interval 2,288 to 2,356, measured from ground level. A representative from the Ohio Department of Natural Resources witnessed the cementing of the liner. Following the cementing of the liner, the Mt. Simon interval was cleaned with a caustic solution. A radioactive tracer log indicated the primary disposal interval was 2,800 feet to 2,850 feet.

The well was returned to service July 22. Well No. 4 had been accepting approximately 20 gpm during the workover of Well No. 3. The combined flow rate after July 22 was 83 gpm. The pressure differential between casing and tubing on August 10, 1980 was recorded at 110 psi (recorders) and 160 psi (gauges).

The tubing was removed August 12 and found to have an "elongated split one inch long" at 2,307 feet. The tubing was replaced, and the well was returned to service. The pressure differential continued to average about the same as on August 10.

The tubing was removed September 13, 1980, and a leak was found at 2,375 feet. The tubing was replaced and the well returned to service. The pressure differential was recorded to be in the range 85 to 150 psi during the next several months (Figure 8).

In November, 1980, Well No. 3 accepted 83 gpm at approximately 700 psi during a short period while Well No. 4 was shut down. Typical flow rates of 65 gpm at 550 psi were recorded at No. 3 during this period with both wells in service.

On December 23, the tubing was removed from Well No. 3 and found to have a leak at 2,689 feet. The tubing was replaced and the well returned to service. The pressure differential was recorded to be approximately 100-120 psi during the following week.

On January 13, 1981, the tubing was again removed from Well No. 3. Pressure tests with a packer established a leak in the interval 2,407-2,467. The rate was reportedly "3 barrels per minute" (126 gpm) at 400 psi (density of liquid unknown). The interval 2,407-2,438 reportedly accepted fluid at "1.5 barrels per minute" (63 gpm) at 800 psi. Three unsuccessful attempts were made to seal this zone with Epseal. However, the zone 2,319-2,690 feet was squeezed with cement March 5, 1981 with apparent success. The cement was drilled out with a 4.75 inch diameter bit.

The well was not operated during the next several months. In July 1981, the interval 2,365 to 2,395 was drilled with a 4.625 inch diameter bit. A TV survey showed resin or cement adhering to the walls of the fiberglass casing. A casing scraper was run from 2,365 to 2,791 feet with a 4.875 inch diameter bit. Fiberglass injection tubing was installed with an inflatable production packer set at approximately 2,712 feet. Injection of fresh water down the tubing at 650 psi produced no increase in pressure on the annulus.

The well was returned to service July 10, 1981 but the pressure differential fell to zero the same day. The tubing and packer were removed and reinstalled. The well was returned to service July 24.

The tubing and packer were removed in August and the packer assembly, which had suffered corrosion, was replaced. The well was returned to service August 28.

The tubing and packer were removed again in September 1981. Tubing and packer were reinstalled and the well was returned to service November 1.

The shear plug that was released from the packer during the last reinstallation had lodged in the fiberglass tailpipe below the packer, restricting flow into the disposal zone. This plug was pushed out of the tailpipe November 10, but the casing pressure rose to 700 psi when injection was resumed. A new packer was installed and the well returned to injection November 13, but the packer was found to be leaking. The packer was redressed and reinstalled and the well returned to service November 16.

In the next several months, the casing pressure gradually rose. By August, 1982, the casing pressure was 80-100 psi greater than the injection pressure (Figure 8), indicating communication either between the tubing and annulus because of a hole in the tubing, or between the open hole and annulus because of bypassing of the packer.

In November, 1982, the flow rate into Well No. 3 suddenly rose from 30 gpm to 50 gpm. At the same time, the flow rate into Well No. 4 suddenly decreased from 60 gpm to 40 gpm. This suggests that Well No. 3 began to "thief" part of the flow because of a sudden improvement in injectivity. However, the recorded injection pressures for the two wells did not change.

2.2.5 Well No. 4: A construction diagram of Well No. 4 is shown on Figure 10. Initial injectivity testing of this well in November, 1976, indicated the well would accept 50 gpm at 575 psi surface pressure. Injection of a buffer of 1.5 million gallons of fresh water was completed in August, 1977 and waste injection started August 31. A summary of the operating history is shown in Figure 11. Due to declining injectivity in the following months, the tubing was removed in November, 1977, to prepare the well for cleaning. The tubing was found to be covered with a precipitate below a depth of 1,200 feet. A mixture of water and sand was injected into the well in order to clean the formation face, then the well was reassembled and tested. Injection pressure was at a flow rate of 50 gpm was 400 psi. The maximum test pressure was 1,600 psi, which resulted in a flow rate of 300 gpm. The Mt. Simon Formation may have been hydraulically fractured during this test. The well was returned to service in May, 1978.

The conductivity cells attached to the tubing of Well No. 4 were found to be unreliable indicators of the type of fluid adjacent to the cells. Occasional independent readings of flow rate were taken at Well No. 4 in mid-1978, and the well was found to be accepting only 16-19 gpm at a pressure of approximatley 580 psi. During the next two years, Wells 3 and 4 utilized a common totalizing flow meter.

Injection pressure at Wells 3 and 4 rose in late 1978 (Figure 11). In March 1979, Well No. 4 was shut in for maintenance. A radioactive tracer survey was made, which reportedly indicated that the whole Mt. Simon interval was accepting fluid. The well was stimulated with explosives set in the Mt. Simon zone. The charges were covered with 5 sacks of Calseal cement and 400 feet of sand. Detonation resulted in a spout of water that was reportedly 20 feet above ground level. The sand was reverse-circulated from the well. Loss of circulating fluids was experienced as soon as the working depth went below the end of the long

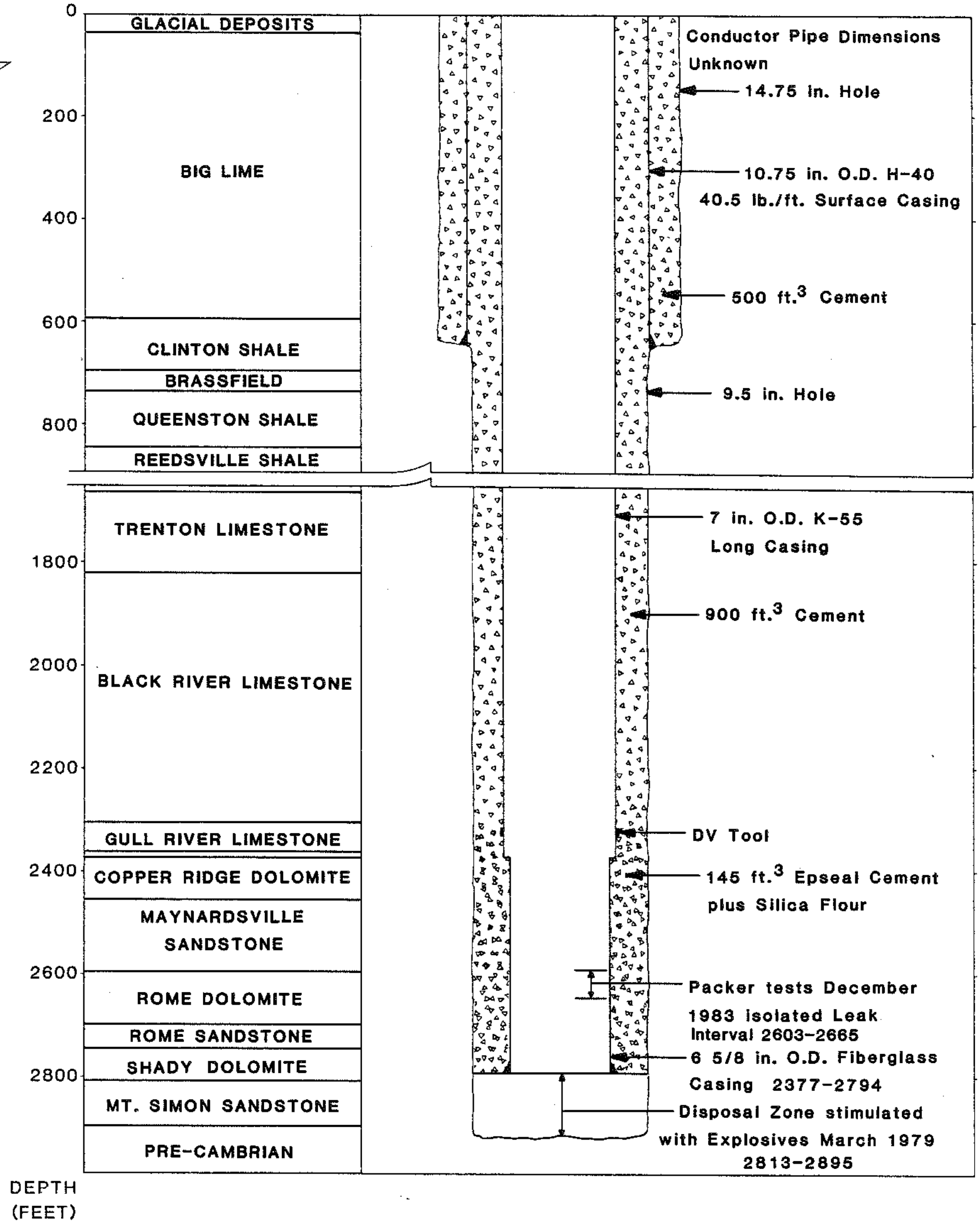



Figure 10. Stratigraphy and Completion Diagram, Well No. 4

string casing. The tubing became plugged with a piece of Calseal during the clean-out operation. Cable tools were substituted for rotary tools and the cleaning was continued. After drilling for six feet, the work string was pulled, and it was found that the bit and jars had been lost in the hole. During fishing operations, pieces of Epseal were reportedly recovered. Washing of sand from the hole was continued without recovery of the cable tools. The well could not be washed below 2,895 feet (measured from the drilling floor).

Another tracer test was run (May 9) and the results reportedly indicated that the fiberglass was not leaking. The cable tools were abandoned in the hole and the well was returned to service. The conductivity cells were reportedly working properly at this time. In late 1979, the pump pressure at Wells 3 and 4 began to fall. In early 1980, the combined flow into Wells 3 and 4 was increased by changing the pump cylinders. During this period, oil was added to the annulus of Well No. 3 on several occasions. A separate flow meter was installed at each well in May 1980. A liner was installed in Well No. 3 in June to repair a leak, which was possibly the cause of the pressure decline. During this repair, the flow rate into No. 4 was 20 gpm. Well No. 3 was returned to service at 65 gpm, and Well No. 4 continued to operate from the same pump as No. 3, at 20 gpm. This was essentially the flow rate and pressure that existed before No. 3 was repaired. Well No. 3 was taken out of service again in January 1981, as a result of the differential pressure between casing and tubing being abnormal since the previous workover. While Well No. 3 was inoperative, the flow rate into Well No. 4 increased 20 gm, and the tubing pressure rose 150 psi (Figure 11) to 40 gpm and 700 psi.

A packer was installed in Well No. 3 and the well was operated in August and September of 1981. The flow rates into Wells No. 3 and No. 4

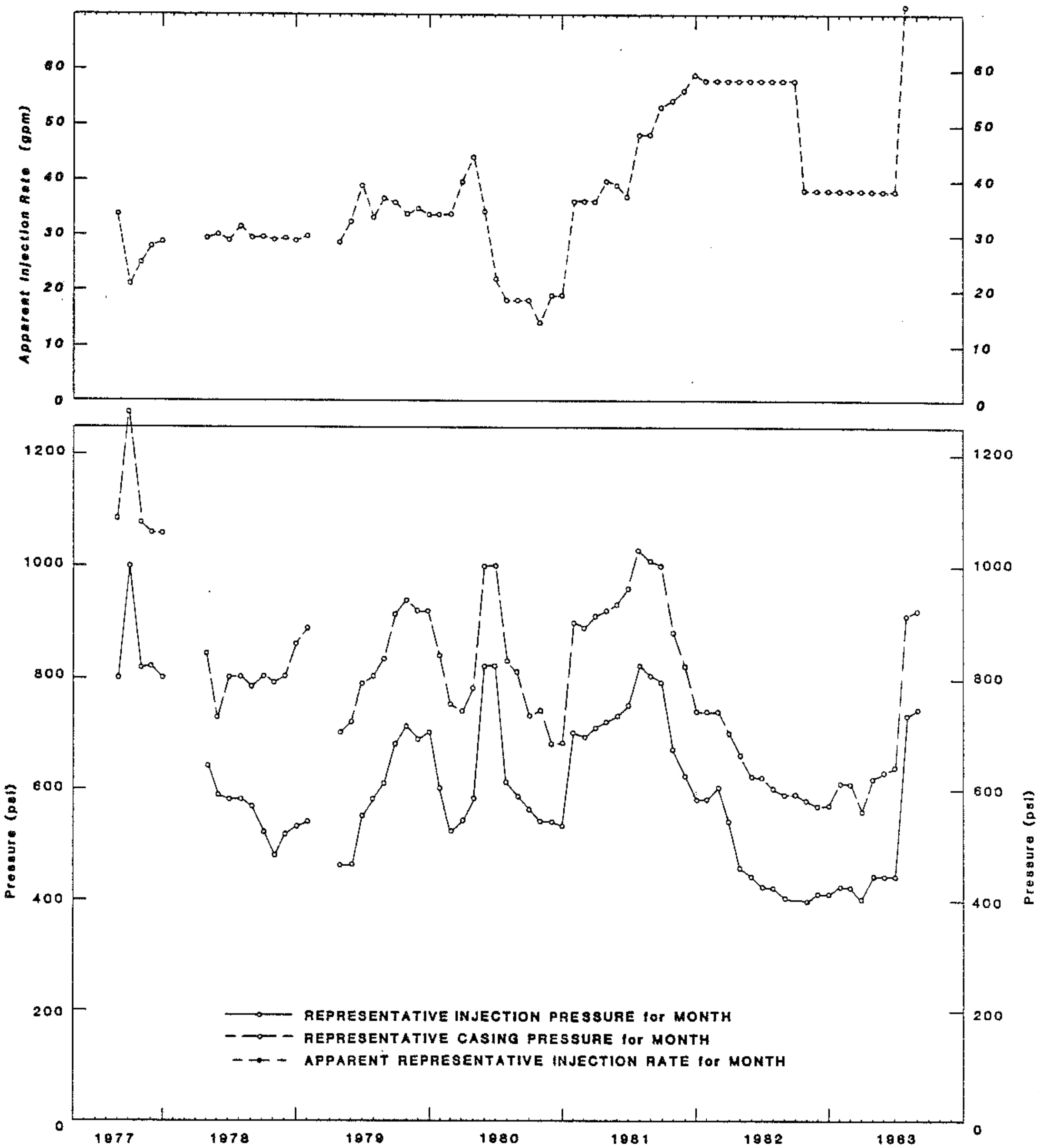



Figure 11. Summary of Operating History, Well No. 4

were 46 gpm and 50 gpm, respectively, at a pressure of 800 psi. Well No. 3 was taken out of service for packer repairs in October, 1981. Starting at this time, the flow rate into Well No. 4 began to gradually increase to 60 gpm, while the injection pressure fell to 700 psi.

Well No. 3 was returned to service, and the flow rates into Wells 3 and 4 stabilized at a reported 30 gpm and 60 gpm, respectively. The injection pressure at these flow rates slowly declined through mid-1982 from 600 psi to 400 psi. During this period, the tubing in Well No. 3 apparently developed a leak, since the annular pressure began to rise. Previously, the annulus had been isolated from the tubing by the packer, and the pressure had been measured at 200 psi. During the following months, the differential pressure between tubing and casing in Well No. 3 was 60 to 100 psi. In November, 1982, the flow rate at Well No. 4 suddenly fell from 60 to 40 gpm, and at the same time, the flow rate into Well No. 3 suddenly increased from 30 to 50 gpm. As mentioned previously, this suggests that Well No. 3 began to "thieve" part of the flow because of a sudden improvement in injectivity. A leak was subsequently found in Well No. 3 in September, 1983, as described in a later section. The recorded injection pressure reportedly did not change when the leak started in November, 1982.

<u>2.2.6 Well No. 5</u>: A construction diagram of Well No. 5 is shown on Figure 12. Injection of fresh-water buffer into Well No. 5 began May 23, 1981. The initial flow rate was approximately 13 gpm at 840 psi, but the rate soon fell to 8 gpm. The well was acidized and the rate increased to 15 gpm at 750 psi. In late May, the reservoir zone was stimulated with three 120 foot-long pieces of explosive cord, acidized, and a tension-set packer was installed at 2,758 feet. Injection of buffer was resumed at 27 gpm at 840 psi. A summary of the operating history of Well No. 5 is shown on Figure 13.

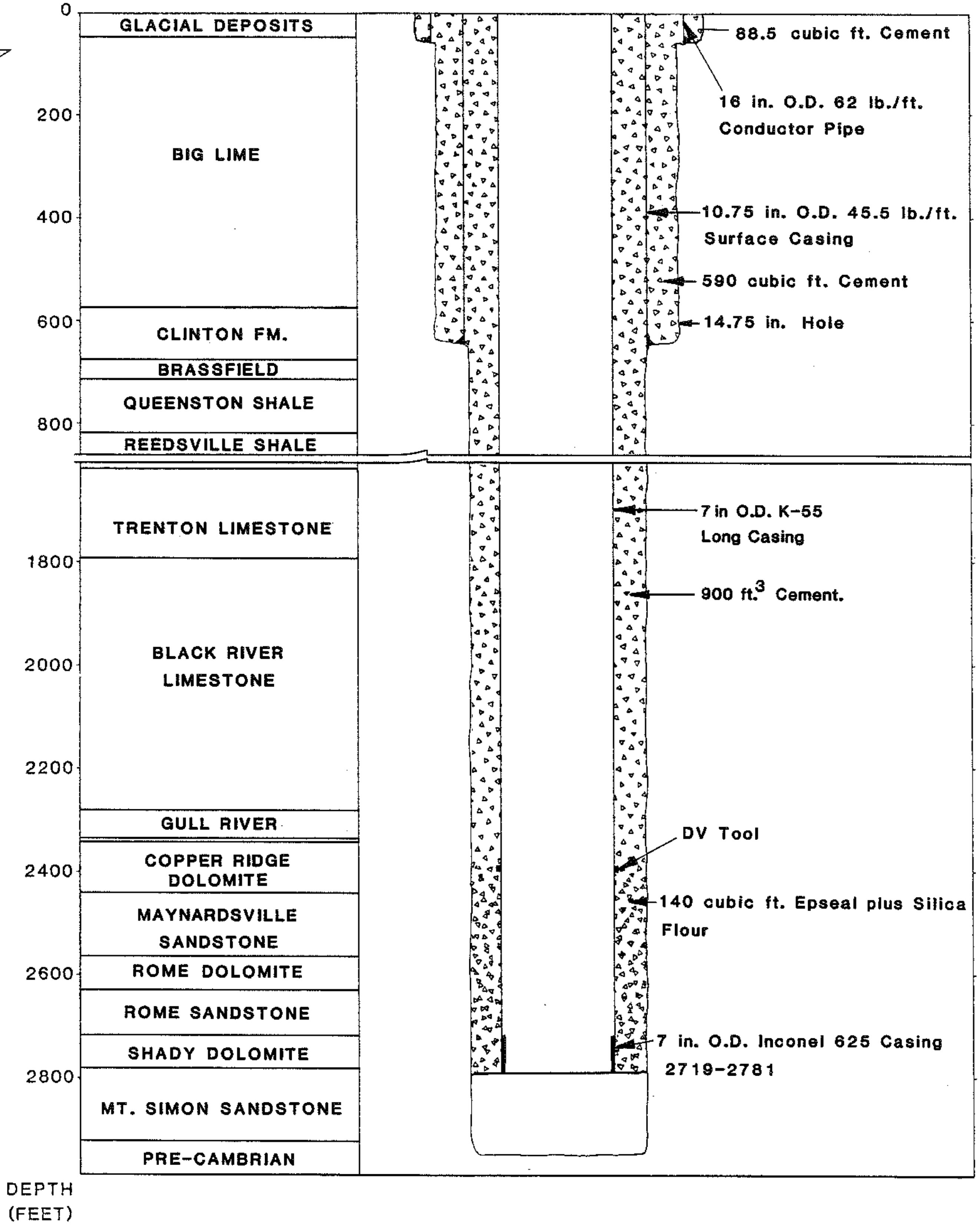



Figure 12. Stratigraphy and Completion Diagram, Well No. 5

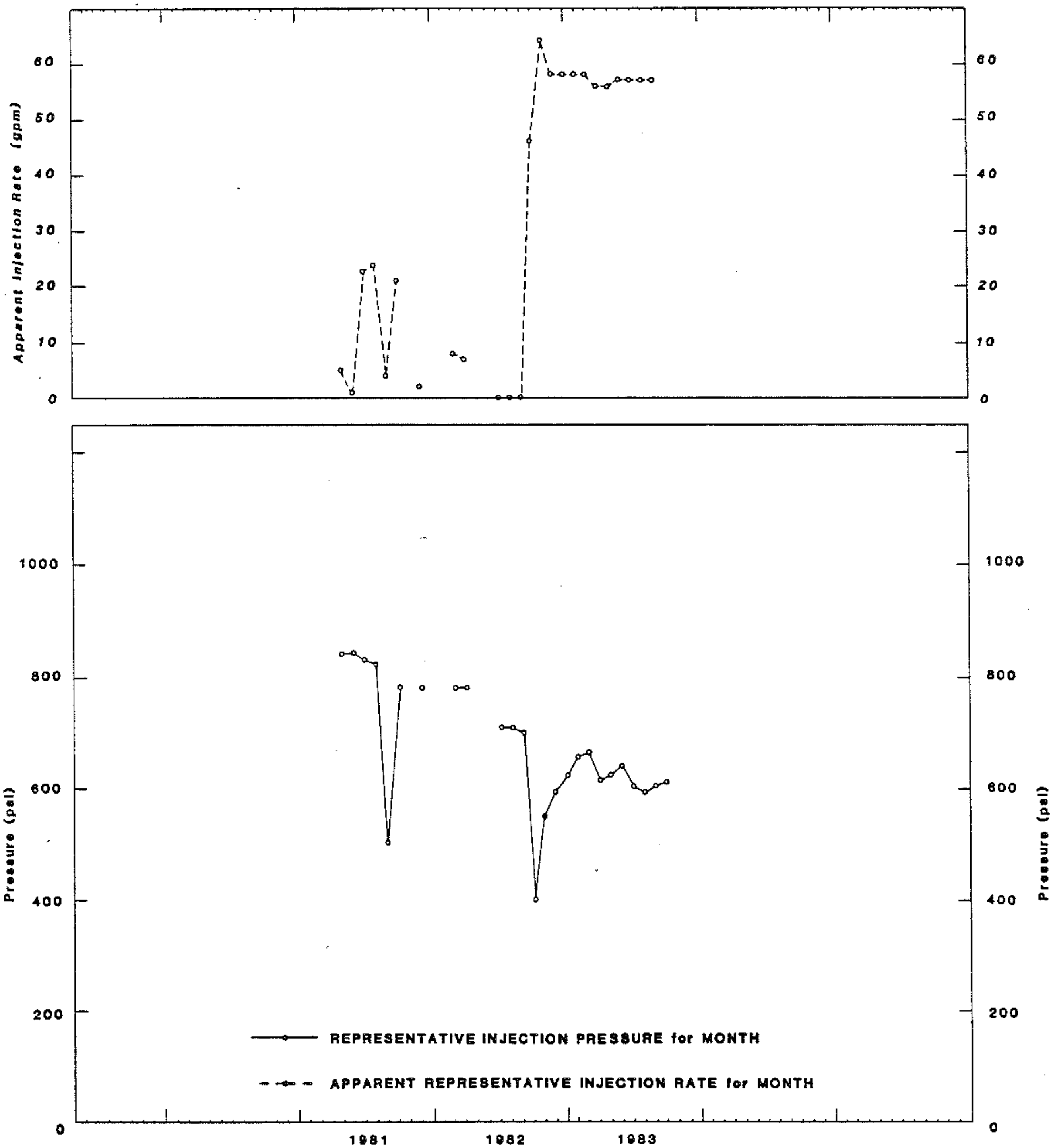



Figure 13. Summary of Operating History, Well No. 5

The flow rate declined to 9 gpm within two weeks and the well was again acidized. Injection of buffer was resumed at 44 gpm and 840 psi. The total buffer volume was over 1,240,000 gallons, with a final flow rate of 35 gpm at 840 psi in early August, 1981.

A rise in casing pressure in early August indicated that either the packer was not sealing, or there was a leak in the tubing. The packer was redressed and reset in September.

The casing pressure rose again in October, 1981, waste acid was found inside the top of the casing, and the tubing was found to be parted at a depth of 15 feet. The tubing and packer were fished out, 12 joints of tubing were replaced, the packer was redressed, and the well was reassembled. The well was returned to service at 30 gpm at 780 psi.

The casing pressure rose again in late October, 1981. The tubing was found to be parted at 1,503 feet. The tubing and packer were fished out, and the packer was redressed and reinstalled.

The well was returned to service November 10, but the tubing parted after 30 minutes of injection. The part was at approximately 965 feet. Tubing was repaired and reinstalled with an inflatable packer. This packer was unsatisfactory and was replaced with a tension-set packer on December 8, 1981, and the well was returned to service. By the latter part of December, the flow rate was only approximately 9 gpm at 780 psi. The well was acidized, but injectivity was not substantially improved. The acid had been displaced at 42 gpm at 1,000 psi surface pressure.

The well was idle until March, 1982. The tubing and packer were removed and the Inconel casing was scraped. The scraper "hung up" at

2,774 feet, according to records. The well began to backflow acid.

The tension packer was reset and the well returned to service March 19. The casing pressure rose in early April, and the packer was reset. Pressure readings appeared to be abnormal and the packer was removed again. The well was idle until June, when the tension-set packer was replaced with a polished bore receptacle with tailpipe. This packer was set in the hole and tubing equipped with a seal assembly was run in the hole and located in the receptacle. The well was returned to service on July 19 at approximately 10 gpm at 700 psi. The casing pressure rose in August. Flow rate was maintained at approximately 10 gpm until October.

On October 13, 1982, Well No. 5 was hydraulically fractured with 10-20 mesh sand as proppant. Six hundred thirteen barrels of fluid were displaced through tubing set on a tension-set packer. The bore receptacle was replaced in the hole, and tubing with seal assembly was located in the receptacle. The first attempt at inserting the seal assembly was unsuccessful. It was found that the bore had become plugged with calcium sulfate, apparently due to backflowing of waste acid. The packer, seal assembly, and formation faced were mechanically cleaned and the well was successfully reassembled and returned to service. Since that time, the well has accepted approximately 67 gpm at 600-640 psi. However, the casing pressure rose in December, 1982, and has remained approximately 220-230 psi higher than the tubing pressure since that time. A differential pressure of this magnitude suggests that the point of communication is near the bottom of the hole, probably at the packer or seal assembly.

2.2.7 Well No. 6: During the completion of this well, cement was drilled out inside the casing, just above the D. V. tool at 2,359, and the float shoe at the base of the Inconel section of the long casing was also drilled out. A construction diagram is shown on Figure 14. When washing loose fill from the Mt. Simon interval, chunks of hard white material were circulated out of the well. The formation was acidized, and the acid swabbed out. Two days later, three joints of work string became plugged with a "white granular material" (probably gypsum) while circulating solids and possibly some spend acid from the well. Several days later, while still clearing the well of solids, fluid was reportedly flowing at the surface; the specific gravity of the fluid in the well was reported to be 1.15.

On May 22, 1981, a tension-set packer was installed at 2,774 feet, inside the Inconel casing. Injection of fresh-water buffer began the next day at 22 to 26 gpm and 840 psig surface tubing pressure. A summary of the operating history is shown on Figure 15. The well was acidized on May 30.

On June 15, the well was air-lifted through continuous one-inch tubing and gray and black solids were reportedly removed. Fill at 2,874 feet was too hard to penetrate with the coiled tubing.

On June 21, a downhole TV camera was used to inspect the well. The casing was reportedly in apparent good condition. A type of coating was observed in places on the Mt. Simon in the open borehole.

The well was stimulated with explosives from 2,875 to 2,925 feet June 25, and acidized June 26. Acid was displaced at 5 barrels per minute at a wellhead pressure of 1,600 psi, according to records.

Injection of fresh water was resumed at approximately 45 gpm and 650 psig.

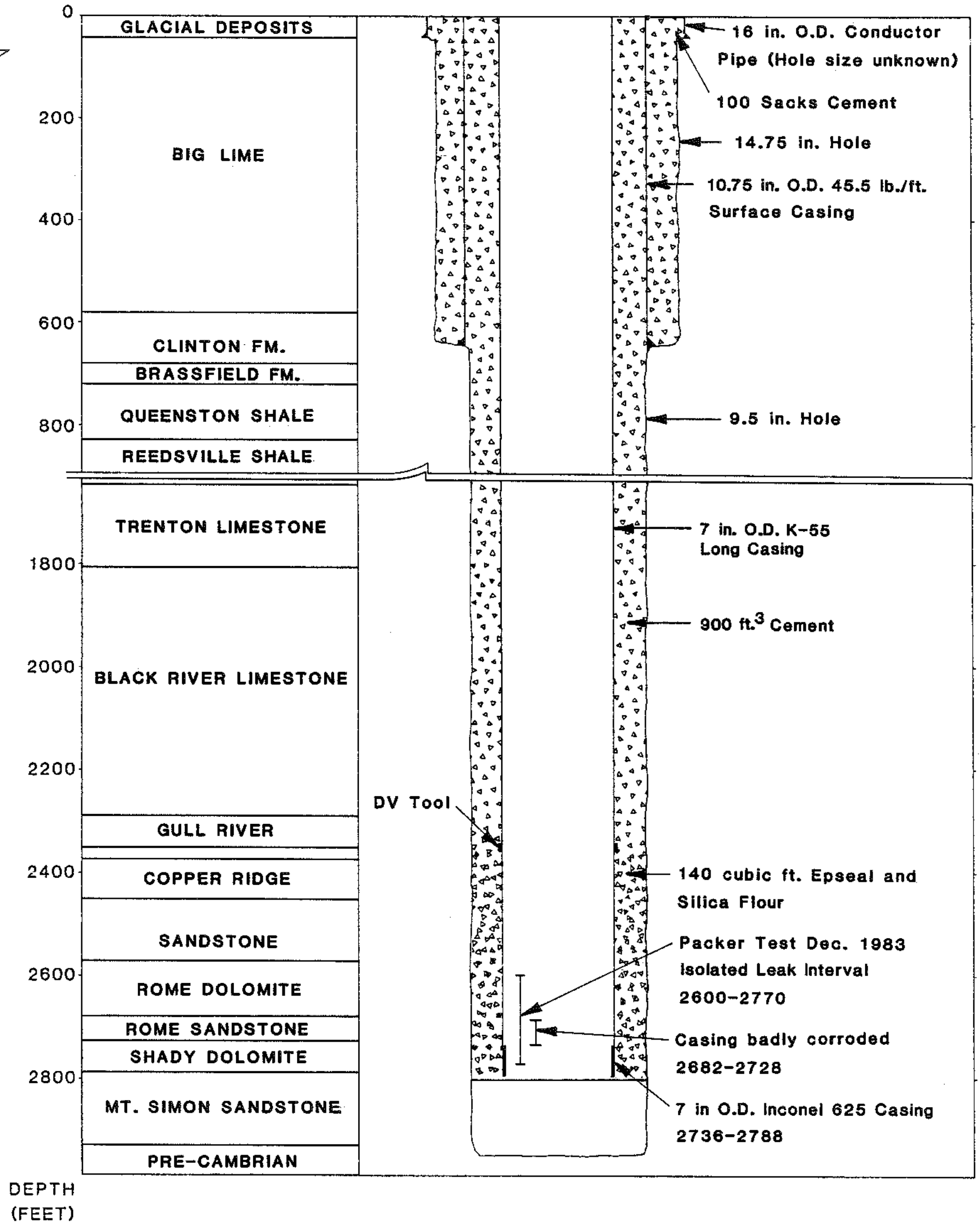



Figure 14. Stratigraphy and Completion Diagram, Well No. 6

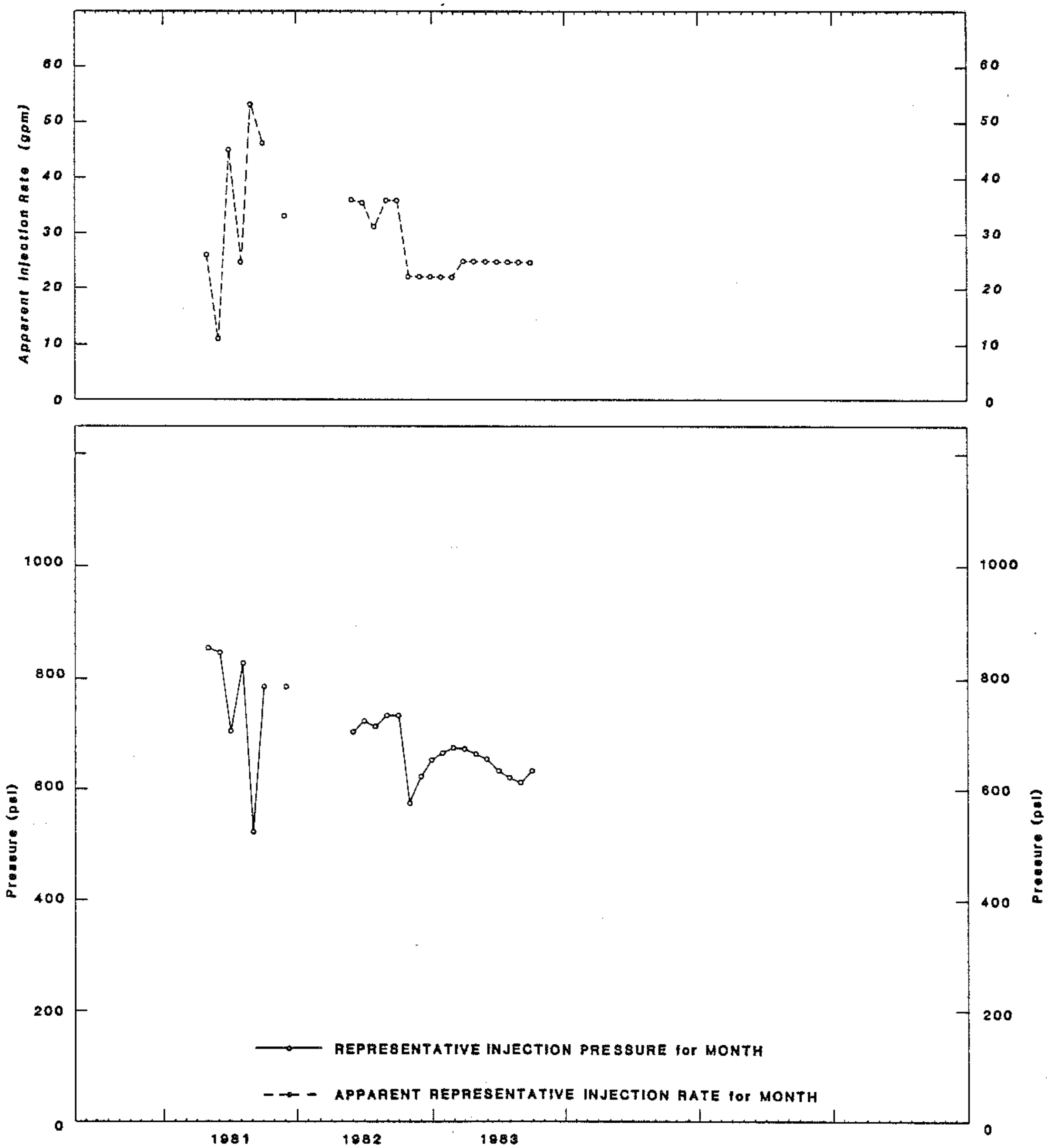



**Figure 15. Summary of Operating History, Well No. 6**

In late July, 1981, the packer was reset. Buffer injection was completed August 13, after a reported total of 2,422,373 gallons had been injected.

Injection of waste began September 21, 1981. After two weeks and injection of approximately one million gallons of waste, it was apparent the packer was not functioning properly since the casing pressure had increased. No oil was found in the casing. The tubing was found to be parted at the surface, inside the wellhead. A casing inspection log reportedly showed that the steel casing was in "excellent condition" with 98.6% remaining of the original wall thickness. The well was idle until December 9 when it was reassembled with two packers. A tension-set packer was run to approximately 2,774 feet and an inflatable packer was run 30 feet higher and set at approximately 2,737 feet. The well was returned to service at 43 gpm at 780 psig on December 11.

By late December, the casing pressure was again rising, indicating communication between the tubing and the annulus. The well was acidized through the tubing and packer, and then flushed with fresh water. The well was idle for the next 2-1/2 months.

On March 16, the tubing and packers were removed from the well. A scraper was run in the Inconel casing. A tension-set packer was reinstalled on fiberglass tubing and the well was returned to service.

After six hours, the casing pressure increased and the well was reopened. A split pipe joint was found on the 16th joint of tubing. The tubing and packer were fished out of the hole, and a scraper was run in the hole to an unspecified depth. A packer/polished bore receptacle assembly was installed on a workstring, and then tubing equipped with seal assembly was run in the well, diesel oil was added, and the seal located in the receptacle. Injection was resumed June 27, 1982.

By July 6, the injection and casing surface pressures equalized, and then the casing pressure exceeded the tubing pressure due to bouyancy. By mid-August, the differential pressure was approximately 200-215 psi indicating communication around the packer. Injection continued at approximately 22 to 25 gpm at tubing pressures of 600-700 psig until late 1983.

## 2.3 Integrity Testing in Fall 1983

In 1983, Chemical Waste Management began to implement a plan to make the wells at the Vickery site conform to federal UIC (Underground Injection Control) regulations. The Ohio Environmental Protection Agency retained URM as a consultant to help advise on the adequacy of test design and to witness a series of mechanical integrity tests of these wells. The testing program consisted of the following procedures:

1. Pressure Test of long casing.
2. Caliper Log of long casing.
3. Tracer Test to determine points of fluid exit and possible upward migration of fluid outside the casing.

In addition, a two-well injection test was performed in order to evaluate the hydraulic properties of the disposal zone. The integrity testing program was designed by CWM consultants and URM with active participation by CWM and OEPA.

Management of the testing program in the field was carried out under the direction of CWM consultants. URM staff was present during all testing in order to observe testing and suggest changes to OEPA and

CWM where necessary.

2.3.1 Well No. 1A: When Well 1A was shut down for testing, it was operating at 40 gpm with an injection pressure of 670 psig. The casing pressure was 930 psig. The daily activity log of the testing, which is summarized here, appears in Appendix A.

After the oil was removed from the annulus, the well was filled with brine of high specific gravity (approximately 1.2) in order to "kill" the well to prevent waste from flowing back to the surface. The heavy fluid is needed to balance the elevated fluid pressure in the Mt. Simon Formation caused by operational injection of waste.

The fiberglass injection tubing and the attached cable for conductivity measurements were removed from the well. Approximately the last 200 feet of tubing was covered with white precipitate. The cable was found to be parted, and approximately 200 feet were left in the hole. The cable was fished out of the hole, and a 40-arm caliper casing inspection log was made.

The log showed that the upper 7" OD steel casing ended at a depth of 2,344 feet and had inside diameters ranging from 6.65 to 6.4 (at 1,530) inches, equivalent to wall thickness of 0.175 inches to 0.30 (at 505) inches respectively (API standard .317 inches for J-55 23lb/ft). No isolated areas of corrosive attack were apparent. The fiberglass casing showed inside diameters ranging from 5.3 to 5.59 inches. The outside diameter is 6.625 inches. The range of wall thickness is .6625 to .5175 inches. The only place in this casing with a visible, localized pit or recess was at a depth of 2,618 feet. The caliper deflection was 0.17 inches.

An inflatable packer was placed in the hole at 2,781 ft. Before the packer was set, fluid was flowing from the casing into the mud pit at an estimated rate of 2-4 gpm. Inflation of the packer did not shut off this flow.

By moving the packer to different depths, a leak was found in the fiberglass casing in the interval 2,591 to 2,606 feet. The casing accepted fluid at a rate of 50 to 100 gpm (depending on assumed efficiency of the triplex positive displacement pump). Flow rates were determined by visually counting the frequency of pump strokes. The pressures necessary to achieve these flow rates were measured by pressure gauge at the top of the mud column (casing head) and ranged from 200 to 350 psi. The leak was squeezed with Epseal and with cement, but this failed to completely eliminate leakage. The well was reworked in November, 1983.

2.3.2 Well No. 2: Well No. 2 has not been in service since December 1980. In testing performed in January 1981, a packer was set at 2,376 feet, and 10 barrels of brine were pumped into the casing at a reported a rate of three barrels per minute (126 gpm) at a pressure reported to be 90 psi. The packer was moved to 2,225 feet and reportedly held 1,000 psi for 10 minutes.

A casing profile log was run September 30, 1983. The log indicates corrosion of the 5 9/16-inch O.D. steel liner located between the depths of 1,903 and 2,364 feet. No major anomalies are apparent within the interval cased with fiberglass, but there is a small (approximately 1/8-inch) enlargement of the diameter at a depth of 2,442 feet.

A packer was installed on work pipe at a depth of 2,423 feet. Casing pressure was raised to 508 psi, and fell to 482 psi after 35 minutes. There was some indication that the wellhead may have a small leak. The packer was moved to 2,500 feet. Brine was pumped into the casing at a rate of approximately 1.9 gpm, as measured by counting strokes of the pump during repressuring cycles. (Pressure repeatedly fell to 350-380 psi in approximately one minute after being raised to 560-580 psi). There is a small leak between 2,423 and 2,500 feet at present. It is possible that backflow of acid has occurred from the Mt. Simon zone through the casing and up into the leak. Precipitation of gypsum in the leak area since 1980 may have resulted in partial plugging of the casing opening or the rock formation into which fluid is leaking (Maynardsville sandstone is present at this level).

2.3.3 Well No. 3: When Well 3 was shut down on August 16, it was operating at 50 gpm with an injection pressure of 390 psig. The casing pressure was 520 psig.

After the oil was removed from the annulus, the well was filled with brine of high specific gravity (approximately 1.2 gm/cc) in order to "kill" the well to prevent water or waste from flowing back to the surface. Removal of tubing was begun. The tubing had parted at 1,300 feet. The last section of tubing removed was discolored. Using tubing and packer, the steel casing from 1,200 feet to the surface was tested at 1,038 psi. Pressure loss was 1.3% in one hour, well within the allowable loss of 3% (see Chapter 3).

A workstring was connected to the top of the free end of the fiberglass tubing at 1,300 feet. Rotation failed to release the packer, so the tubing was cut with a small explosive charge just above the packer and removed. The tubing was discolored from the top (which had been installed at 1,300 feet) downward, and the discoloration gradually disappeated downward, so that the last 100-200 feet appeared normal. A crack approximately one foot long was evident at the box end of the top of the fiberglass tubing that was fished from the well.

A combination casing profile caliper log/gamma log was run in the hole in order to examine the condition of the casing. Corrosion of the 7" steel casing was not evident except at a depth of 1,227 feet, near the apparent leak in the tubing. At this point pitting to a depth of approximately .08-.19 inch was indicated. The surface of the fiberglass casing, located below 2,358 feet, appeared to be rough and irregular, and showed variations in diameter up to 0.6 inch. This may be due both to removal of material by scraping and to addition of material such as resin and cement during previous repair procedures.

Using an inflatable packer, a leak was located in the fiberglass section of casing between the depths of 2,389 and 2,626 feet. The tubing and packer were removed in preparation for reworking of this well.

After milling out the damaged casing below a depth of 2,365 feet, a 40-arm casing inspection log was run in the upper, remaining casing, and corrosion of the casing was noted at a depth of 580 feet. This corrosion had not been detected by the earlier 3-arm profile log, which is less sensitive and has less complete coverage of the circumference of the casing. As a precaution, the casing was again pressure tested and found not to be leaking.

2.3.4 Well No. 4: When Well No. 4 was shut down for testing October 27, 1983, the flow rate was 72 gpm and the flowing surface pressure was 690 psi. The casing pressure was 880 psi. Before the companion Well No. 3 was shut down in August, the flowing pressure into the two-well system had been approximately 420 psi and casing pressure was

620 psi. The oil was removed from the casing of Well No. 4 and the well was killed with 10 lb/gallon brine. The tubing was removed, along with the cable to the anode system. The tubing was discolored and coated with a thin film of precipitate on the bottom 400 feet.

An inflatable packer was set at 2,780 feet. Brine was pumped into the casing for a short period at a rate of approximately 60-70 gpm at a pressure of 175 psi. The packer was released and moved to 2,656 feet and the same results were obtained. The packer was released and moved to a depth of 2,594 feet and pressured to 513 psi; the pressure fell slowly to 442 psi in 45 minutes. The packer was released and moved to a depth of 2,333 feet. The casing pressure was raised slowly to 700 psi. When the pressure reached this level, the casing began accepting fluid. The pump was stopped and the pressure fell immediately to 608 psi, where it held steady for ten minutes. This behavior indicates that one or more holes are located in the casing above 2,333 feet. The hole(s) is (are) probably opposite low-permeability rock. When the pressure is raised to 700 psi, the formation probably is hydraulically fractured and will accept fluid at measurable rates. Below this pressure, no significant flow appears to occur. The casing pressure has been at a level of approximately 620 psi (surface) during most of the previous year and a half. It is probable, therefore, that the casing defect above 2,333 feet was not accepting fluid (oil) during operation.

It should be noted from the above that integrity tests of casing are normally carried out at pressure levels capable of fracturing geologic formations. If there is in fact a hole in the casing, the formation will be exposed to the test pressure. If the hole is opposite a low-permeability formation, it will not be discovered until the formation parts and begins accepting fluid.

In order to estimate the possible magnitude of leakage that occurred into the leak at 2,594 to 2,656 feet during operation, it was decided to perform a short comparative injectivity test. The inflatable packer was set at 2,777 feet. Brine was pumped into the casing at approximately 89 gpm at 200 psi. The flow line was disconnected from the casing and connected to the work pipe. The pressure was slowly raised to 1,500 psi in order to shear the pin in the plug and choke assembly at the bottom of the packer to allow communication with the lower part of the well, which is open to the Mt. Simon Formation. Brine was pumped into the work pipe at approximately 44 gpm at 200 psi. It is inferred that more than half of the injected waste may have been entering the leak, probably into the Rome Dolomite or lower Maynardsville sandstone.

A 40-arm caliper casing inspection log was run. No major holes were detected by this log. The average I.D. of the steel casing appears to be approximately 6.64 inches. The original O.D. was nominally 7.0 inches. A three-arm caliper log was run, and on this log the average inside diameter is approximately 6.2 inches. The fiberglass casing has an inside diamter of 5.4 inches on the 40-arm log, and 5.2 inches on the three-arm log.

2.3.5 Well No. 5: When Well No. 5 was shut down for testing on November 7, 1983, the well was accepting 67 gpm at 610 psig surface pressure. The oil was removed from the annulus and the well was killed with 10 lb./gallon brine. The packer/polished bore receptacle assembly that had been installed in the 60-foot section of Inconel at the bottom of the long casing was not in place. The packer/bore assembly was fished from the hole using the workstring.

Several attempts were made to set an inflatable packer near the depth of 2,775 feet. The packer elements failed by splitting longitudinally. A 40-arm casing inspection caliper was run. The caliper tool had considerable drag in the Inconel casing. The caliper log suggested that the Inconel casing may have some minor restrictions, possibly due to out-of-round pipe or a precipitate. The average I.D. of the Inconel measured at 6.4 inches. The I.D. of the carbon steel casing averaged approximately 6.6 to 6.7 inches, which would be considerably enlarged if the original nominal I.D. was the standard 6.366 inches. Rust particles were abundant in fluid swabbed from hole.

An inflatable packer was set at 2,700 feet. Pressure was raised to 770 psi and bled off at 5 psi/min. Since a wellhead leak was suspected, pressure was released in order to weld the wellhead. The pressure was again increased, this time to 1,000 psi immediately, with a slow decline to 500 psi in 15 minutes. The packer was moved to 1,260 feet, above the perforations that were made for remedial stage cementing of the upper 1,300 ft. of the long casing. The pressure was raised to 1,000 psi, but fell immediately to 582 psi and held steady for 10 minutes.

The packer was set at the following depths: 480, 540, 782, 902, 1,145, and 1,135 feet and the casing was pressured to 1,000-1,200 psi. There was a slow bleed off at each setting of approximately 0.4 to 1.0 psi/minute. The packer was set at the following depths: 1,205, 1,250, 1,266, and 1,295 feet, and the casing was pressurized to 1,000 to 1,200 psi. At the settings of 1,266 and 1,205 feet, the pressure initially dropped quickly, but appeared to stabilize at 725 and 1,175 psi, respectively. It is possible that the rock formations opposite leaking points in the casing were inadvertently fractured. The stabilized bottom hole pressure (at the packer) divided by depth to the packer would have been approximately 1.1 and 1.5 psi/ft. at 1,266 feet and 1,205 feet, respectively, which should have been enough pressure to fracture the formation.

A retrievable, inflatable packer was set at 2,768 feet in order to test the lower part of the casing. A second packer was set at 1,290 feet and the straddled interval of casing pressurized to 982 psi. The pressure fell to 906 psi in 15 minutes and 860 psi in 65 minutes, indicating a slow leak in the casing in this interval. The upper packer was moved to 2,406 psi, and the straddled interval was pressurized to 950 psi. The pressure fell to 735 psi in 15 minutes.

2.3.6 Well No. 6: When Well No. 6 was shut down for testing November 7, 1983, the flow rate was 25 gpm at 625 psi flowing surface pressure. The casing pressure was 850 psi. The oil was removed from the casing, and the well was filled with 10 lb/gallon brine. The tubing was removed, and the bottom six joints (120 feet) were found to be slightly discolored with a thin film of precipitate.

An inflatable packer was set at 2,770 feet and brine was pumped into the casing at approximately 60 gpm at 150 psi. The flow line was disconnected from the casing and connected to the work pipe. The pressure was raised in order to shear the plug in the choke in the bottom of the packer. It sheared at the somewhat low pressure of 1,000 psi. Brine was pumped into the work string at approximately 60 gpm at 150 psi for a brief period. As the pump was stopped, brine had begun to flow from the blow-out preventer, which had been opened. Apparently fluid had begun to channel past the test packer.

A 40-arm casing inspection log indicated that the casing in the interval 2,682 to 2,728 feet, just above the basal Inconel section of the casing, had suffered heavy corrosion or complete removal. The diameter indicated by the 40-arm caliper was approximately 7.5 inches.

The packer was installed at 2,600 feet, above the bad section of casing. The casing pressure was raised to 975 psi, and bled off slowly to 820 psi in 5.5 minutes. A leak was observed at the BOP flange. After an unsuccessful attempt to tighten the BOP, the casing pressure was raised to a lower level, 472 psi. No loss of pressure was observed in 15 minutes. It is probable that the casing does not leak above 2,600 feet depth level.

## 2.4 Summary

The well inspection program revealed problems in each of the wells. Some of the problems were apparently due to mechanical damage to the fiberglass casing (Wells 1A, 2, 3, & 4), while other problems were due to corrosion of the steel casing (Wells 5 and 6). In most cases, a direct signal that leakage was occurring was not provided by the monitoring instruments.

The following table summarizes the estimated time that leakage began and the estimated leakage rate for each of the wells at the CWM site. In some cases, the rate was so small that the time the leak began is difficult to identify.

| Well | Estimated Date Leak Began | Estimated Rate of Leakage (gpm) | Estimated Volume of Leakage (Millions of Gallons) |
|---|---|---|---|
| 1* | Unknown | Unknown | Unknown |
| 1A | December, 1981 | 7 to 20 | 7 to 20 |
| 2* | Early 1979 | 2 to 5 | 1.5 to 4 |
| 3 | October, 1982 | 20 | 12 |
| 4 | Mid 1981 | 20 | 15 |
| 5 | unknown | less than 1 | Unknown |
| 6 | Mid 1982 | 12 | 9 |

*Well No. 1 was taken out of service in July, 1979.
Well No. 2 was taken out of service in December, 1980.

The wells at the CWM site were operating without a downhole seal between the annular fluid and the injected fluid ("packerless completion"). In this type of well, an immiscible annular fluid (oil or diesel fuel) is allowed to "float" on the injected fluid below the end of the injection tubing. The position of the oil/water interface may be determined by electrical contacts, which have proved to be ineffective, or by measurement of surface pressures. Due to the lesser specific gravity of the oil compared to the waste, the casing pressure measured at the wellhead is greater than the tubing pressure. In order to calculate the length of the oil column, the specific gravities of the two fluids must be accurately known, the casing and tubing pressures must be measured accurately, and if the well is in operation the friction losses in the injection tubing must be known. If the pressure difference is abnormally small, the length of the oil column is too short, and it may be an indication that some of the oil has escaped thorugh a leak in the casing, or that a leak has developed in the injection tubing.

The procedures and equipment employed at the CWM site were not adequate to enable accurate calculation of the length of the oil column. According to plant personnel, specific gravity of the two fluids was measured only occasionally. In addition, the gauges used to measure pressure in the casing and tubing were marked in 20 psi increments. The friction losses in the injection tubing cannot be measured without a downhole gauge, and therefore this pressure loss must be estimated if the well is in operation. This inability to accurately measure casing and tubing pressures and the lack of knowledge of the specific gravity of the fluids prevented the well operators from accurately measuring the length of the oil column within an estimated 200 to 300 feet of the true value, even when the wells were out of service. Thus, leaks near the bottom of the well were very difficult to detect without performing a casing integrity test by pressurizing the casing above a test packer. In the case of Well No. 3, however, the pressure differential was significantly lower than normal for a period of several months due to a hole in the injection tubing at a depth of approximately 1,300 feet.

This type of well completion requires a rather sophisticated level of data collection and interpretation by well operators in order to precisely assess the operating condition of the well.

## 2.5 Recompletion of Wells

The injection wells at the CWM site were being reconstructed under the direction of CWM consultants at the time this report was written. Although details of the individual designs vary, it is planned that the general configuration of all the rebuilt wells will be similar.

The basic design change in these wells is the utilization of downhole seals at the bottom of the casing, between the outside of the injection tubing and the inside of the casing. The casings (or in some cases, liners) will be equipped with polished bore receptacles (PBR's). A PBR is a section of steel or alloy pipe whose interior surfaces have been honed and polished in order to receive a seal assembly, which is attached to the lower part of the injection tubing. The PBR is longer than the seal assembly, which allows the assembly to move up or down in the PBR in response to thermal extension or contraction of the length of the tubing. Therefore, movement does not disturb the seal between the oil-filled tubing/casing annulus and the waste stream, which greatly improves the reliability and longevity of the seal.

The use of a bottom-hole seal means that the protective oil in the annulus can be pressurized at all times independently of the waste fluid in the injection tubing. The casing of each rebuilt well will be connected to a reservoir of oil near the wellhead. The reservoir will be provided with a sight glass to allow visual measurement of the oil level in the reservoir. The space above the oil in the reservoir will be pressurized with nitrogen gas to 1,000 psi. If a leak develops in the casing, the oil will be forced out of the leak and the level in the reservoir will drop. If a leak develops in the tubing, waste will be injected into the casing and the level in the reservoir will rise. In either case, the well can be quickly shut down to await repair.

## CHAPTER THREE - INJECTION MONITORING

### 3.1. General

Regulatory surveillance of injection activities ordinarily consists of several distinct activities: operational monitoring, periodic inspection, and integrity testing.

Observation and recording of key operational parameters provides information necessary to properly evaluate well performance for both engineering and regulatory needs. These parameters include total volume of injected waste, injection rate and pressure, casing (annulus) pressure, and volume of protective annular fluid system. The cumulative volume of injected wastewater should be recorded to allow estimation of the distance of wastewater invasion, interpretation of long-term pressure trends, and to provide a permanent record of the volume of injected material. Periodic inspection of the facilities should be done to ensure that measurement instruments and the other surface equipment are in good condition. Integrity testing should be scheduled at regular intervals to ensure that downhole equipment is operating properly and that fluid is entering only the intended formation.

### 3.2 Operational Monitoring

3.2.1 General Requirements: A key measure of the operating condition of a well is the flow rate per unit increase of pressure at the formation face, sometimes called injectivity or injectivity index. A more practical index is flow rate per unit of surface operating pressure ("apparent" injectivity), since pressure is ordinarily measured at the wellhead rather than at the formation face.

Injectivity is dependent on several factors, including the permeability and thickness of the disposal reservoir, the temperature of the injected fluid, the degree of sand-face plugging ("skin effect"), and the rate and duration of prior injection (formation pressure buildup). Skin loss causes an unwanted, usually repairable, loss of injectivity, while buildup of formation pressure is unavoidable and results in the necessity to slowly increase the injection pressure over time in order to maintain the same flow rate, yielding a gradual, slow decrease of injectivity.

Apparent injectivity is a measure of the injectivity plus several additional factors that depend on the design and condition of the well hardware. These factors include pipe friction pressure losses in the injection tubing and leaks in the system.

Gradual increase of apparent injectivity may indicate either dissolution of sand grains or native mineral cements in the rock formation, resulting in locally increased permeability around the wellbore ("negative skin effect") and an improvement in well efficiency, or it may indicate development of a slow leak in the casing. It may also indicate a leak in surface piping.

Sudden increase of apparent injectivity may indicate development of a major leak in the casing. It may also indicate a leak in surface piping.

Gradual decrease in apparent injectivity is a common occurrence as the reservoir pressure builds up due to injection or as multiple wells in a well field begin to interfere with each other. Greater-than-normal rates of decrease may indicate plugging of the face of the disposal formation with solids ("positive skin effect").

The second key measure of the condition of the well is volume of protective fluid in the annulus between the casing and the injection tubing. In wells that do not have bottom-hole packers or seals to separate the annular fluid from the wastewater in the well in the disposal zone below the end of the tubing, the annular fluid is usually a nonaqueous, bouyant liquid, such as oil. The oil "floats" on the wastewater and prevents contact between the wastewater and the casing and the outer wall of the tubing. Contact is not prevented if some of the annular fluid is lost. Therefore, it is important to know the volume of the oil, or in other words, to know the position of the oil/water interface in the annulus of the well. The location of the interface can be measured by indirect and/or direct methods. The direct method employs downhole electrical contacts attached to the injection tubing and connected by wires to a conductivity meter at the surface. Measurement of the conductivity of the liquid adjacent to the downhole contacts should enable the operator to distinguish between high-conductivity aqueous waste and the low-conductivity oil of the annular system. The conductivity is supposed to confirm that there is sufficient oil to cover the deepest contacts. A rise in the interface indicates loss of oil and possible casing leakage. A second direct method of determination of the location of the interface is to physically remove the oil and measure its volume.

The indirect method involves measurement of the difference in pressure between the tubing and the casing. In wells that do not have bottom-hole packers to isolate the annular fluid from the injection fluid, the pressure of the annular fluid is controlled primarily by the pressure of the waste liquid in the casing or open borehole below the annular fluid. In wells such as those at the CWM site which use oil-based annular fluid, the pressure at the top of the casing is greater than the pressure at the top of the injection tubing due to bouyancy caused by the lower specific gravity of the oil. The amount of the difference between tubing and casing surface pressures is an indication of the depth to the interface between the two fluids. An abnormally low differential pressure indicates loss of oil, resulting in an abnormally short column length of oil (rise in the interface) and possible casing leakage. However, the pressure differential is affected by additional factors, including specific gravity of the waste and of the oil, and tubing friction losses if the well is operating. If these factors are known, the operator's ability to estimate the true depth of the interface depends on the accuracy of the gauges used to measure surface pressures.

In wells that have bottom-hole packers or sealing assemblies, the annular fluid is isolated from the flowing wastewater system. The annular fluid system in this type of well, which has been chosen as the new design for wells at the CWM site, can be pressurized independently and monitored for a direct indication of casing leaks.

The measurement equipment should be capable of accurately measuring flow rates and pressures. In addition, wells with downhole seals for the annular fluid system should have a means of detecting loss of annular fluid. The wells should be equipped with devices to immediately signal the operator if problems develop.

It is desirable to maintain automatic, continuous records of flowing pressure, annulus pressure, and flow rate rather than periodic (for example, hourly) spot readings of these parameters. Significant events, signalled by changes in apparent injectivity, may occur between manual readings. A continuous, automatic record of transient events can help provide insight into the nature of a problem for both operators and regulators.

3.2.2 Present System and Suggested Requirements: The equipment employed now at the CWM site appears to be adequate to make continuous records of operating parameters, with a few exceptions noted below. The wells are equipped with separate pressure transducers connected to tubing and casing. The transducer signals are sent to the pump house, where they are continuously recorded on a strip chart. In addition, the tubing and casing of each well are also equipped with standard indicating dial pressure gauges. These gauges are read hourly by the operators, providing a check on the automatic instrumentation. Presently, the standard gauges are marked with 20 psi increments. It is recommended that these gauges be replaced with ones marked in 5-psi increments, in order to more accurately provide independent calibration of the automatic readings. If the manual and automatic gauges begin to disagree, the manual gauges should be recalibrated with a dead-weight tester, and then checked for agreement with the automatic recorders.

The pressure recording equipment at CWM is connected to sensors set to detect abnormally high or low pressures. If the disposal formation begins to become plugged with solids, a pressure increase above the set limit will trip the detectors. Conversely, the low-pressure sensors will be tripped in case a major downhole or surface leak occurs.

Flow rates are currently measured with rotary flow meters set on the suction side of the pump. Each pump operates two wells. The company has not successfully operated rotary meters in the high pressure flow lines. Therefore, an external meter is employed on the flow line to one well of the pair. This meter detects sonic signals from the pipe and electronically calculates the flow rate. The rate measured by this equipment is read periodically and manually recorded. By subtracting this rate from the rate measured by the rotary meter in the pump input line, the flow rate to the second well of the pair can be calculated.

Since this system does not provide a continuous record of the flow rate to each well, transient events may not be recorded, except at the rotary meter. It may be difficult to identify which well caused the anomaly. A superior system would provide continuous recordings of the flow rate in each injection line.

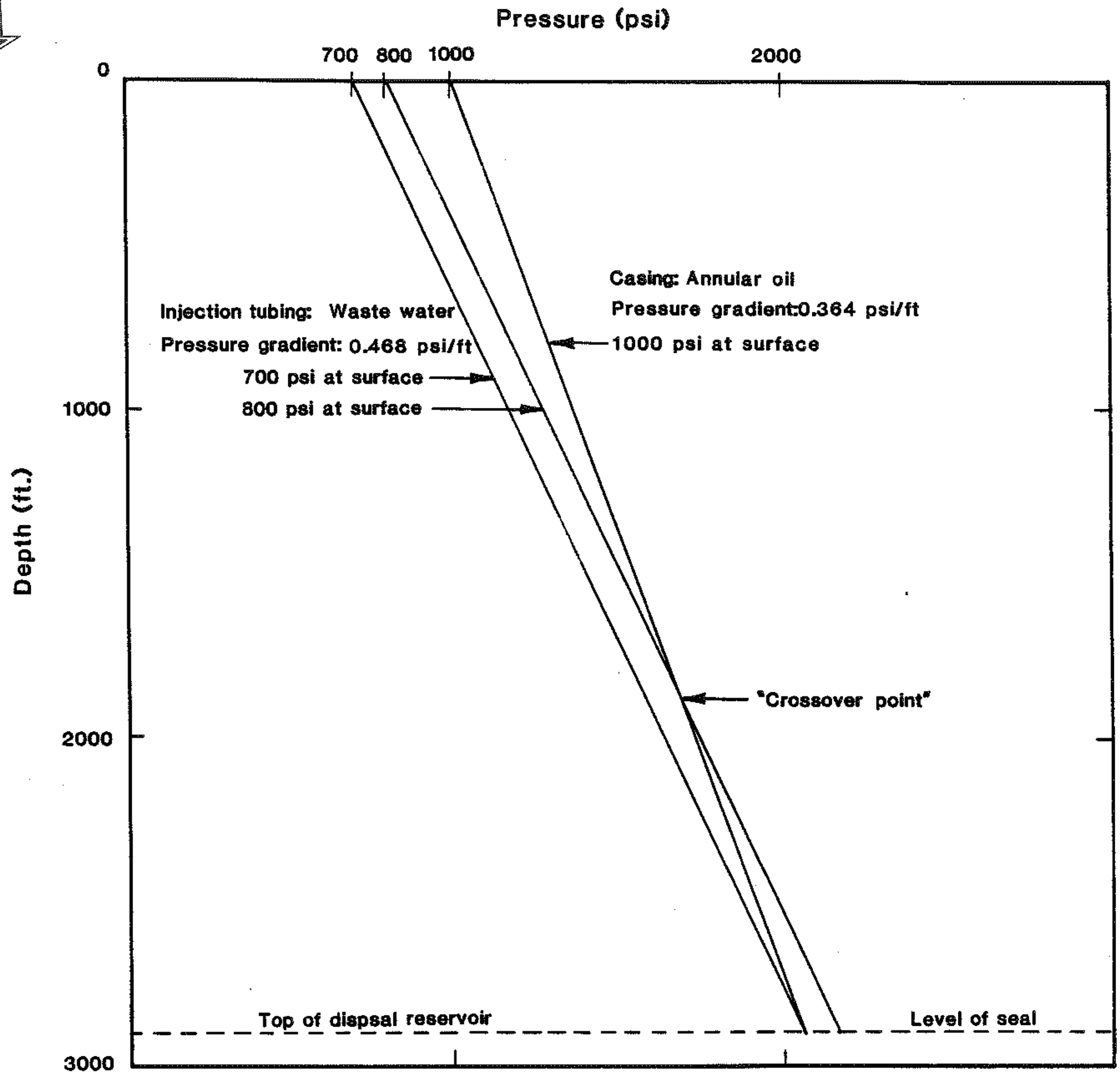
The primary shortcoming of the past operational system at CWM was the method of determining volume of annular fluid. A rise in the oil/waste interface may expose non-resistant casing materials to the waste stream. The wells have not had working bottom-hole annular sealing systems in the past, and have been subject to the limitations of both the direct and indirect methods of measuring interface position.

The electrical conductivity measurements at downhole contacts or anodes have not proved to be reliable at this site. Similar problems have been experienced with this type of system at other sites. The problem is that the conductivity measured at the surface is not always the true conductivity of the fluid adjacent to the electrical contact. The contact may be affected by such factors as thin films of the second or foreign fluid, corrosion, encrustation, or faulty wiring. This system was gradually abandoned by CWM when these problems became apparent.

Use of the pressure differential between tubing and casing to establish the depth of the fluid interface has not proved to be sufficiently accurate to detect small (but significant) changes. For example, if the density of the waste were 1.085 gm/cm$^3$ (9.03 lb./gallon) and that of the oil were 0.85 gm/cm$^3$ (7.07 lb./gallon), then a change of one foot in the depth of the interface would cause a change in the pressure differential of 0.1018 psi. The leaks at CWM have occurred approximately 60 to 300 feet above the disposal zone. A rise of oil-water interface by 60 or 300 feet would cause a change in differential pressure of 6.11 or 30.5 psi, respectively, assuming the above densities. If the densities are not periodically determined by measurement, and if the friction losses within the tubing of flowing wells are not known, the true relationship between change in differential pressure and change in depth of interface is uncertain. The gauges employed for these measurements at CWM in the past have been marked in 20-psi increments, which would limit the precision of the measurements, even if the above relationship were known.

These problems should be overcome if the wells are recompleted with bottom-hole bore receptacles and seal assemblies as planned by CWM. The annular space in this system becomes a pressurized oil jacket surrounding the injection tubing from the surface to the depth of the disposal zone. The annulus is connected to a reservoir of oil whose contents can be directly observed at any time by means of a sight glass. The reservoir is pressurized with a nitrogen pad to 1,000 psig. The resulting bottom-hole pressure in the annulus is approximately 2,030 psig. The oil would tend to be forced out of any leak that develops in the casing, and an immediate indication of this situation is registered as a falling level in the reservoir and sight glass.

The annular monitoring system should also register tubing leaks. The casing pressure, if maintained at 1,000 psi at the wellhead, will be higher than the tubing pressure at every depth in the well except when the surface tubing pressure exceeds approximately 710-760 psi, depending on flow rate and resultant pipe friction losses (Figure 16). In those areas where casing pressure exceeds tubing pressure, a tubing leak will result in leakage of annular oil into the tubing and a falling level in the reservoir and sight glass. If tubing pressure exceeds the casing pressure near the bottom of the well, a tubing leak in this area would




Downhole pressure profiles in disposal well with seal between waste water and annular oil. When tubing pressure is raised above 700 psi, the tubing pressure exceeds the annulus pressure in the lower part of the hole. In this case, a leak in the upper tubing causes a drop in the annulus-oil level; a leak in the lower tubing would cause a rise in the annulus-oil level.

**Figure 16. Downhole Pressure Profiles**

result in flow of wste into the annulus, which would result in a rising level in the reservoir and sight glass.

The continuous records of flow rates and of pressures at the tubing and casing should be used to generate monthly reports on the operating status of the wells to be submitted to officials of the Ohio Environmental Protection Agency. As mentioned previously, the flow rates and pressures should be measured at the same time, so that the reported pressure represents the pressure actually utilized to achieve the reported flow rate. In this case, a valid apparent injectivity can be calculated for comparison with previous values. If the specific gravity of the waste changes significantly, the injectivity may need to be adjusted accordingly for proper comparison to earlier values. For this reason, specific gravity of the waste stream should be reported monthly or when significant changes occur. It would be advantageous if parameters such as tubing pressure, casing pressure, flow rate, and injectivity index were presented graphically versus time in order to aid rapid recognition of potential problems. It is recommended that leaks or other failures be reported promptly to OEPA.

Pressure measurements should continue to be made when a well is inactive, in order to provide data on the behavior of the entire well field at CWM.

## 3.3 Site Inspection

It is recommended that personnel of OEPA visit the injection well facilities at least every six months to ensure that surface equipment is in good working order. The following items should be included in site visits:

1. Pressure gauges and recorders operating. Readings in agreement

with each other and with previous reports to OEPA. Instruments not exposed to weather. Readings should be recorded.

2. Flow meters operating. Readings of individual flow lines sum to reading on suction line, when one pump feeds two wells. Readings in agreement with previous reports. Instruments not exposed to weather. Readings should be recorded.

3. Pumps, piping, holding tanks, and wellhead in good condition.

4. Annulus fluid reservoir has level consistent with previous reports. Valve to annulus and valves to sight glass open. Level should be recorded.

5. Operating records for the period of time between inspections should be reviewed.

6. Plots of injection rates and injection pressure versus time should be conducted.

## 3.4 Integrity Testing

The disposal wells at the CWM site should be periodically tested to ensure that waste is being injected only into the permitted formation. It is recommended that this mechanical integrity testing be periodically performed throughout the life of the well. A well has mechanical integrity if there are no leaks in the casing, tubing, and packer, and if there is no fluid movement through vertical channels in the cement sheath or adjacent to the wellbore.

Most Federal and State regulations specify allowable pressure bleed off in casing pressure tests or state that generally accepted industry standards should be applied. In many cases, the casing is pressurized to 1,000 psi, and a loss of more than 3% or 5% of this pressure in 30 minutes or one hour constitutes failure of the test. In developing the federal regulations, it was generally recognized that a 5% loss may represent the fluid/casing system coming to thermal and/or elastic equilibrium. How to distinguish between equilibrium and small leaks was ot well documented or explained in the federal guidelines. The tolerance standards were adopted to enable testing to be completed in a reasonably short time, since it may take several days to reach complete equilibrium if there are large temperature differences between the wellbore and the test fluid. In summary, the current tolerance standards for casing tests may be too high. It is suggested that each test be evaluated with all possibilities in mind. A plot of casing pressure versus time should help to distinguish between steady leaks and transient equilibrium.

Most regulations specify that temperature or noise logs be run to demonstrate the absence of upward migration outside the base of the casing. Most regulations permit substitution of other tests, such as the radioactive tracer log, for this purpose due to the limitations of temperature and noise logs. Interpretation of radioactive tracer logs is comparitively straightforward. Currently, radioactive tracer logs are more frequently performed than temperature or noise logs.

PART B

Hydrogeologic Environment

# CHAPTER FOUR - GEOLOGY

At the CWM site, waste liquid is injected into the Mt. Simon Formation at a depth of approximately 2,800 ft. The Mt. Simon Formation is a sandstone that occurs in a number of states and in Canada in the Great Lakes Region. It is usually the deepest sedimentary rock unit encountered by drilling. Due to the depth of the formation and its location directly over the Precambrian surface in most of the region, it has been penetrated by fewer wells than the shallower rock units. Besides petroleum exploration boreholes, a number of wells have been been drilled to the Mt. Simon, including those used for disposal of waste liquids and for storage of natural gas.

The following sections briefly describe the structure, stratigraphy, and seismicity of Ohio, with emphasis on the Mt. Simon Formation and conditions in northwestern Ohio.

## 4.1 Structure

Sandusky County, Ohio is located near a structural flexure between two Paleozoic-age continental basins (Figure 17). Structural maps of either the Mt. Simon Formation or the Precambrian "basement" surface reflect subsidence of the Michigan Basin to the northwest and the Appalachian Basin to the southeast. These basins are separated by the Findlay Arch (Cincinnati Arch) (Figure 18). The highest elevation at which the Mt. Simon locally occurs is over the crest of the Findlay Arch. In general, the deep sedimentary units in Ohio have gentle dips interrupted by a few small amplitude folds. The Mt. Simon Formation, and many of the overlying formations, thicken northeastward and southwestward into the basins (Figure 19). The Mt. Simon Formation is not present in a large part of Southwesten Ontario, on the north side of Lake Erie. It was eroded from or never deposited on the crest of the

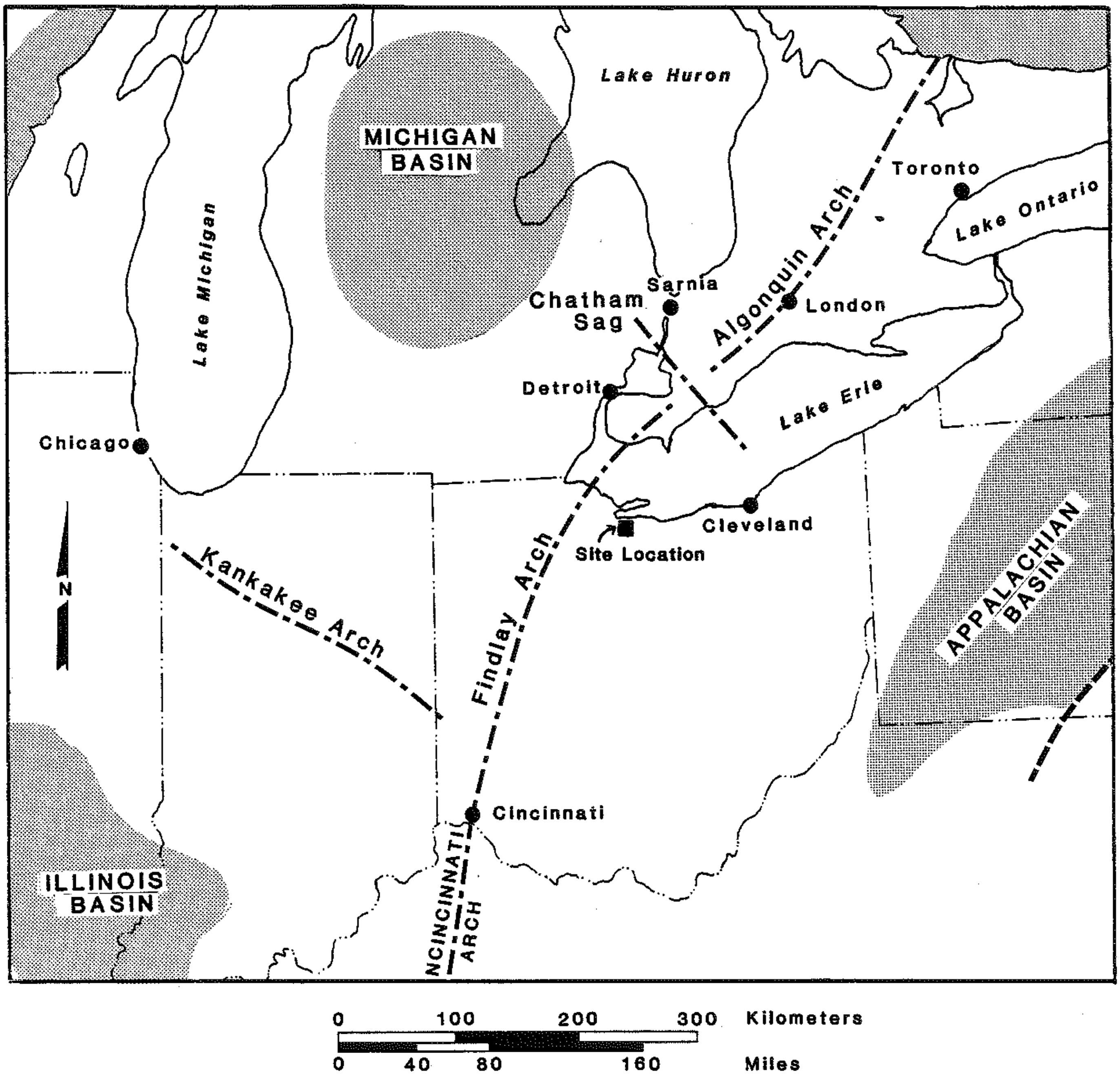
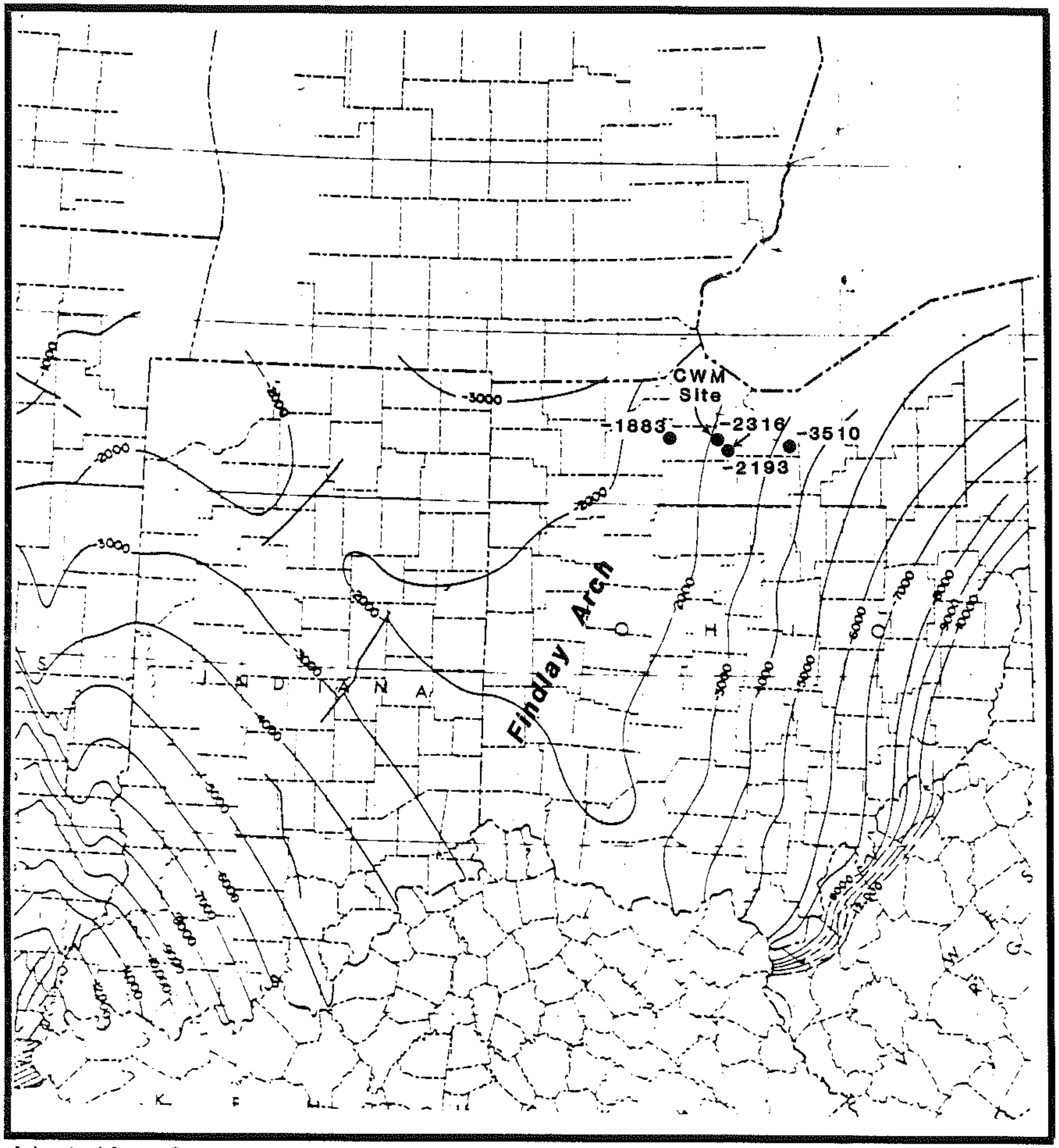



Figure 17. Structural Elements in the Ohio Area

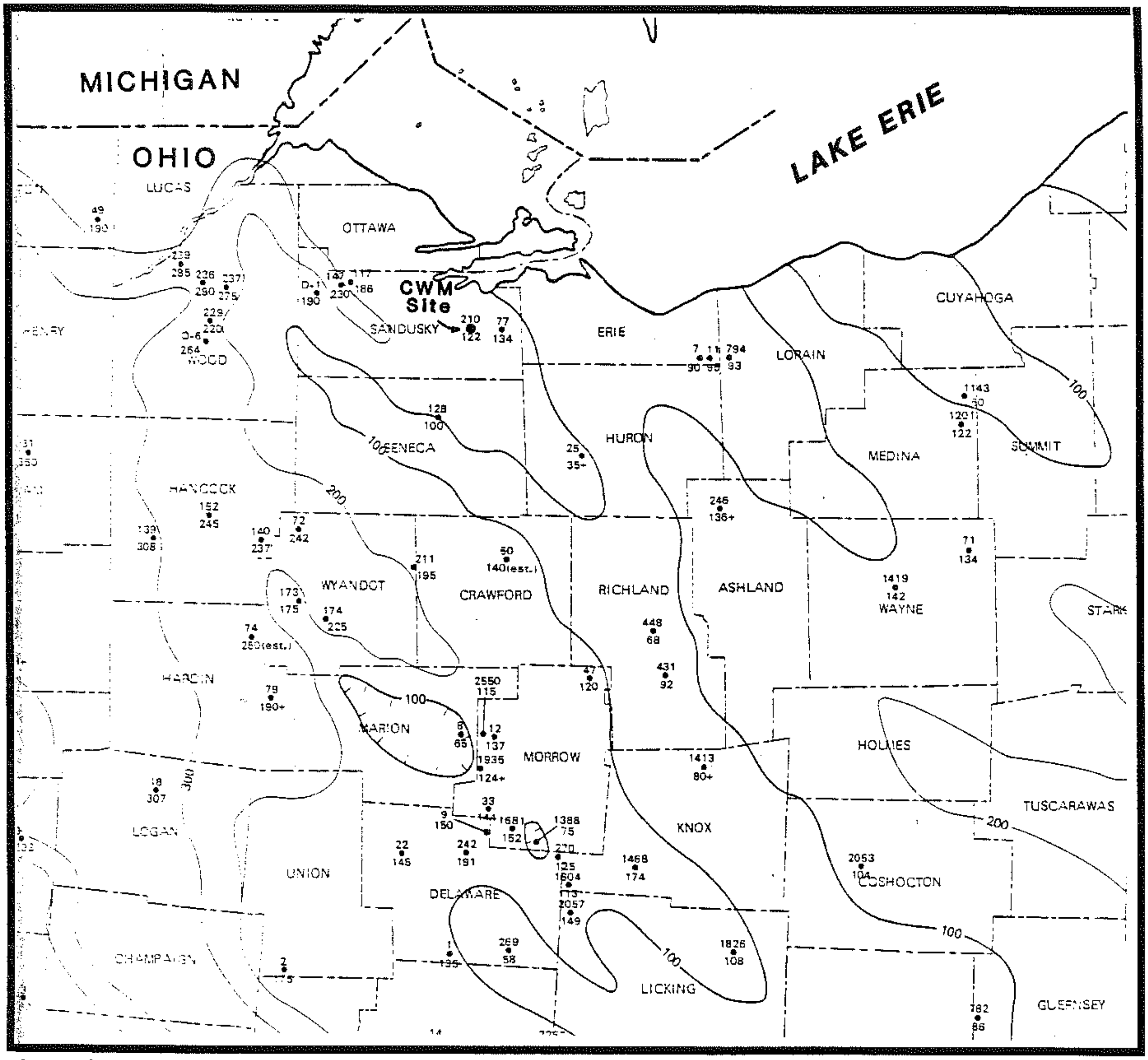



Adapted from Orsanco, 1976

—— -2000 Structural Contour, Feet Below Sea Level.

Scale
0 15 30 60
Miles

Figure 18. Structure on top of the Mt.Simon Sandstone
Elevations at Wells indicated verified by URM,Inc.




from Janssens, 1973

**Explanation**

72 Well permit number
• Well location
242 Thickness (feet) of Mt. Simon Sandstone

— isopach of Mt. Simon Sandstone, isopach interval 100 feet

**Scale**
0 10 20
**Miles**

**Figure 19. Isopach Map of the Mt. Simon Sandstone**

Algonquin Arch, which is another structural flexure that is approximately aligned with the Findlay Arch. The closest point where the Mt. Simon sandstone pinches out is approximately 60 miles from the CWM site.

A significant regional structure in Northeastern Ohio that is possibly interpretable as a fault is the Bowling Green Monocline. This is a north-south trending feature that passes through Lucas, Wood, and Hancock Counties approximately 35 miles west of the CWM site, on the west flank of the Findlay Arch.

Due to the few number of wells that penetrate the Mt. Simon Formation, the existence of possible local, small-scale structural anomalies is not documented. Small anticlines and arches (generally less than 50 feet of closure) have been mapped (Janssens, 1973) at oilfields that produce from stratigraphically higher rocks. The nearest of these structures are near Tiffin in Seneca County (approximately 20 miles southwest of the CWM site) and in Florence Township in Erie County (approximately 30 miles to the east). These oilfields produce from Knox, and at Tiffin, Trenton rocks which are stratigraphically above the Mt. Simon by approximately 400 feet and 1,100 feet, respectively. The structures can be mapped on horizons shallower than the producing zones, indicating that they are not related to the erosional topography of the Knox Unconformity. The structures have been mapped as anticlines, and there is no indication of faulting, according to Janssens (1973). The local structure of the CWM site is discussed in Section 6.3.3.

## 4.2 Stratigraphy

The stratigraphic sequence in Northwestern Ohio is shown on Plate 1. The depth to the igneous "basement" rocks at the CWM site is approximately 2,900 feet. As indicated on Plate 1, the major stratigraphic units are easily traceable in the subsurface from well to well. Most of the units are laterally continuous for significant distances compared to the scale of expected pressure increases in the Mt. Simon disposal zone. The expected increases in pressure are discussed in Chapter 6. Detailed lithologic descriptions of cuttings and core samples from wells at the CWM site are found in consultants reports available for inspection at the offices of OEPA.

The Mt. Simon Formation at the CWM site is overlain by the Shady Dolomite (also called lower dolomite of Rome Formation, Janssens, 1973), the Rome Sandstone, and the Rome Dolomite (Upper Dolomite), all of Cambrian Age. Overlying the Rome Dolomite is the Maynardsville Sandstone. The upper part of the Maynardsville is primarily dolomite or dolomitic sandstone, underlain by sandstone, shale or shaly sandstone, and sandstone, in descending order. The upper dolomitic sandstone and sandstone are also known as the Kerbel Formation, and the shaly section and underlying sandstone are also known as the Conasauga Formation (Janssens, 1973).

Overlying the Maynardsville section is the uppermost Cambrian-age bed, the Copper Ridge Formation (also known as the Knox Dolomite). At the top of the Copper Ridge is the Knox Unconformity (approximately 1,750 feet below sea level). This is an irregular, erosional surface formed when the area was exposed above sea level at the end of Copper Ridge deposition. This horizon can be traced over a wide area, and it is known to produce oil and gas in several locations, including the Tiffin Pool (1,300 feet below sea level) and oilfields in Huron and Erie Counties (2,800 and 3,000 feet below sea level, respectively).

The Unconformity is overlain by the Ordovician Glenwood Shale, the Gull River Formation, and the thick Black River Limestone. The Black

River is in turn overlain by the Trenton Limestone. The Trenton has produced substantial amounts of oil and gas in eastern Ohio, including Sandusky County (see Section 5.1).

The overlying thick Reedsville shale is the lowermost upper Ordovician Unit. The Reedsville is overlain by the Queenston Shale.

Overlying the Queenston Shale is another unconformity, and then the basal Silurian unit, the Brassfield Formation, which is primarily limestone. The Brassfield and the overlying Clinton Formation (also known as the Cabot Head Formation) make up the Cataract Group. These units are in turn overlain by the Devonian-Silurian "Big Lime".

The "Big Lime" is an informal drillers' term that includes, in ascending order at this site, the Dayton and Rochester Formations (also called the sub-Lockport Silurian where differentiation of the units is difficult, west of central Ohio), the Lockport Dolomite, and the Greenfield Dolomite and Tymochtee Dolomite. The Tymochtee forms the bedrock surface at the site. It is laterally equivalent to anhydrite-bearing beds of the Salina Group that occur downdip to the east, and thin gypsum and anhydrite beds are reportedly present in the uppermost 60 feet of bedrock. The "Big Lime" is the primary freshwater-bearing unit at the CWM site.

The bedrock surface is overlain by approximately 65 feet of glacial till and lacustrine deposits.

## 4.3 Seismicity

Seismic events have been associated with injection wells in a few rare cases. These events are thought to occur when fluid pressure in the subsurface near a fault is artificially raised to an elevated level.

An increase of fluid pressure along a fault plane reduces the component of effective stress that is oriented normal to the fault, thereby reducing the frictional resistance to sliding. Sliding (seismicity) can then occur if there is a component of natural tectonic stress oriented paralles to the fault plane (shear stress), and the fluid pressure is raised to some critical level over a large enough area of the fault plane.

Since the susceptibility to induced seismicity should be greater in areas where the natural stress accumulation is greater, the areas of greater risk of induced seismicity should in general correspond to the areas of greater natural historical seismicity. The seismic risk map of the United States (Figure 20) indicates that the Vickery site is in an area considered to have a risk of only minor damage from earthquakes. The most seismically active locations in the vicinity of Ohio are near Anna, Ohio in Shelby County and in northwestern New York. In 1971, a number of microearthquakes were recorded in Western New York near injection wells used for hydraulic mining of salt. An array of geophones installed and monitored by Columbia University (Fletcher and Sykes, 1977) located the source of the tremors near the trace of the Clarendon-Linden Fault, a major high-angle reverse fault. The injection well was located within 200 feet of the fault. None of the earthquakes was reported to have caused damage. This general area had been historically subject to relatively intense earthquake activity.

The Anna, Ohio area has been more seismically active than the rest of Ohio. The last relatively large quake in this area occurred in 1936 and had a magnitude of approximately five on the Richter scale, which was sufficient to do minor damage to buildings. This area has been under scrutiny by the Nuclear Regulatory Commission since 1977. An array of seismic detectors has been monitored since that time for the

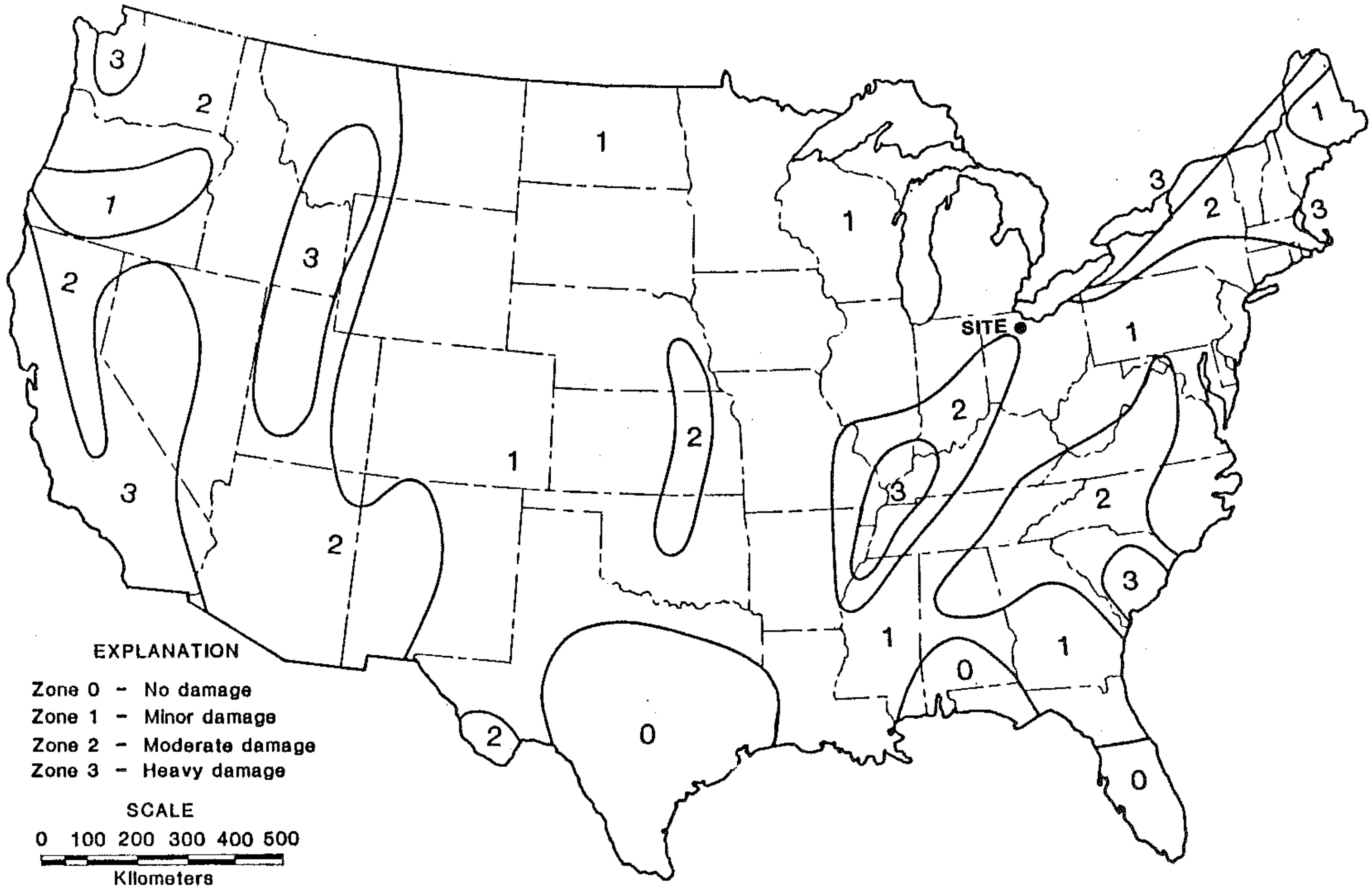



Figure 20. Seismic risk map of the United States

NRC by Department of Geological Sciences of the University of Michigan. Department personnel report that this array is sensitive enough to detect seismic activity near Vickery, Ohio of magnitude 2.0 or greater. This magnitude is near the level at which shocks can be felt by humans near the site. If an earthquake of this magnitude were to occur in northern Ohio, the instrumentation presently in place would be sufficient to give an approximate location of its epicenter. Deep well injection at the Vickery site has occurred under relatively high pressures since 1976. Only one seismic event has reportedly been felt in the area since that time.

A tremor was felt at the site on July 27, 1980. This event apparently originated near Sharpsburg, Kentucky, and was felt as far away as Toronto and Detroit. The intensity of this shock was reported to be 5.3 on the Richter scale. It caused no damage at the site, and there were reportedly no changes in operating pressures during passage of the shock.

An unpublished magnetic anomaly map of Ohio has been examined at the Ohio Department of Natural Resources, and the Vickery site is apparently in an area of relatively minor lateral change in magnetic susceptibility. Areas of rapid lateral change may indicate lateral lithologic differences in basement rocks. Faults (not necessarily active faults) may be expected to be present at the boundaries between lithologically dissimilar basement terrains. The absence of such features near Vickery is another favorable indication that the risk of induced seismicity in this area may be very low. On January 27, 1984, a computer search of the NOAA-ES's Earthquake Data file was conducted. Recorded quakes within 500 km of the Vickory site are located on Figure 21.

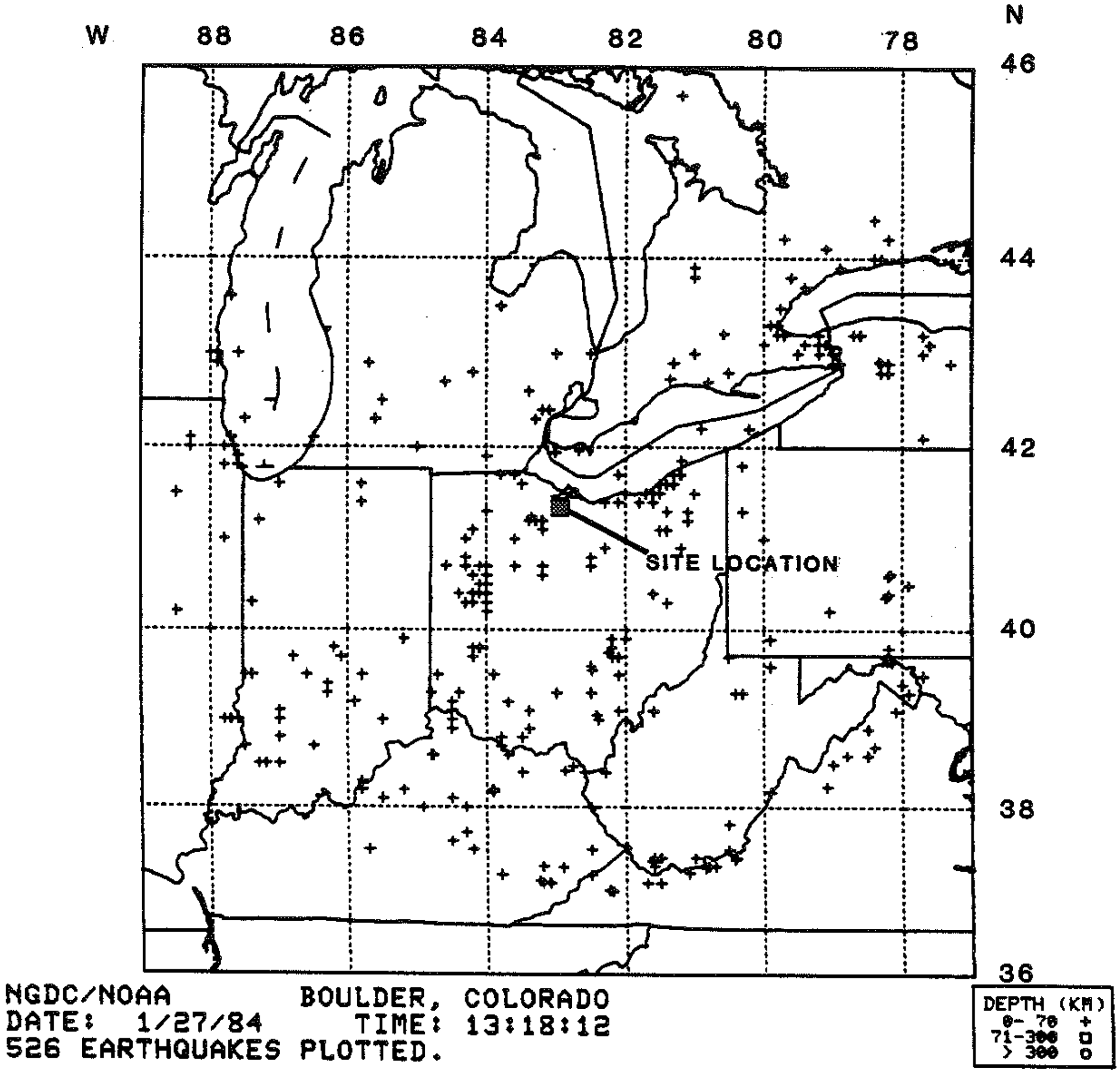



Figure 21. Map of Recorded Earthquakes Within 500 Km. of Vickery Site

# CHAPTER FIVE - NATURAL RESOURCES

Injection of waste liquids into the subsurface should be permitted only in cases where it can be assured that resources such as oil and gas, fresh ground water, and certain mineral brines can be protected. The location of a resource may be known or with some certainty, as in the case of water, brines, and producing oil and gas fields, or the location may be speculative, as in the case of undiscovered oil and gas reserves. In order to protect known or potentially present resources, the hydraulics of injection should be understood.

Permeable underground space is itself a different type of resource. Productive or repeatable use of subsurface space has been termed "positive use" (Van Everdingen and Freeze, 1971). Positive uses include injection of fluids for pressure maintenance to aid recovery of oil, injection of fresh water into brine-bearing aquifers for future recovery and use, and injection of natural gas for temporary storage. Injection of wastes into the subsurface ("negative use") would ordinarily render the receiving formation at that site unsuitable for future positive uses, such as storage of fresh water. However, waste disposal may be considered to be the "highest and best" use of a subsurface horizon if noxious waste is safely removed from the biosphere. The ideal sites to reserve for "positive" use would be structural features such as oil and gas reservoirs that would be capable of trapping bouyant fluids.

The following sections review the oil and gas and water resources in the vicinity of the site. No commercial value is known for the native formation brine in the Mt. Simon sandstone at this site.

## 5.1 Oil and Gas

The major accumulations of oil and gas in northern Ohio historically have been found to lie along two principal trends (Figure 22). To the west, the Trenton trend extends from Mercer County northeastward to Lucas, Ottawa, and Sandusky Counties. This trend was active in the late nineteenth and early twentieth centuries. The trend extends into Sandusky Township, where more than 120 wells were drilled to a depth of approximately 1,300 feet. This area is located approximately six to eight miles west of the CWM site. The Trenton horizon is located approximately 1,130 feet stratigraphically above the Mt. Simon horizon.

To the east, exploration continues at present along a trend from Cuyahoga County to the southern border of Ohio in Lawrence County. The primary exploration target is the Silurian Clinton Sandstone. At the CWM site, this stratigraphic interval is occupied by the base of the "Big Lime" formation which lies at a depth of approximately 600 feet. The nearest part of this trend lies approximately 40 miles east of the CWM site.

The area between these two primary trends contains a few scattered oilfields. Most of these fields produce from the Knox Dolomite, also known as the Copper Ridge Dolomite. This horizon is located approximately 450 feet stratigraphically above the Mt. Simon horizon. The nearest production from this formation is in the adjacent Seneca, Huron, and Erie Counties. The pool near Tiffin in Seneca County was discovered in 1938. The pool in Townsend Township in Huron County was discovered in 1965. The pool in Florence Township in Erie County was discovered in 1966. These pools are widely separated and do not appear to be part of a definable trend or fairway associated with some regional structural or stratigraphic feature.

The Maynardville Sandstone, also called the Kerbel Formation, is considered to be potentially productive, although no wells currently

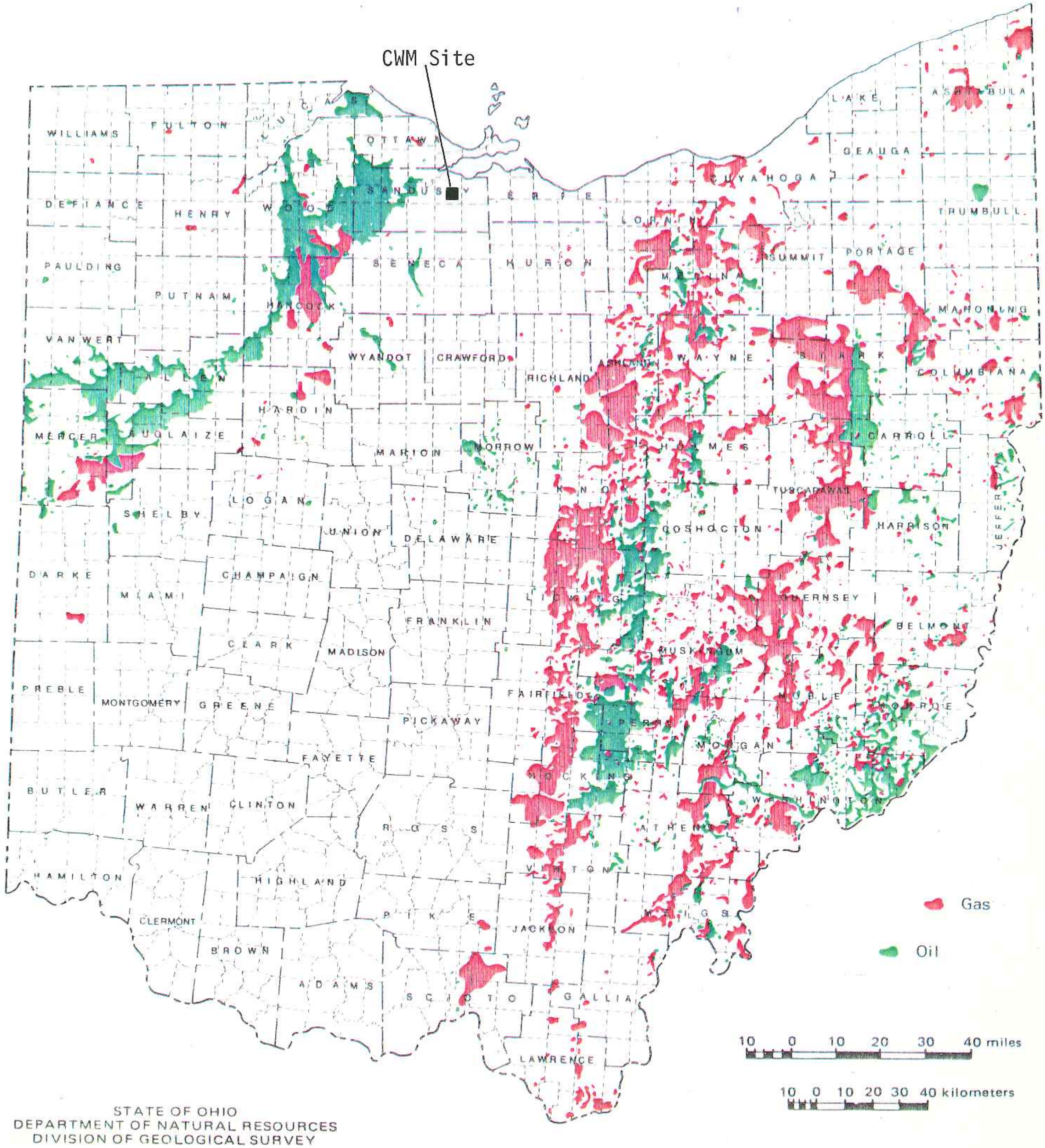



Figure 22

## OIL AND GAS FIELDS OF OHIO

Areas in which oil or gas is being produced or has been produced commercially since 1860.

A detailed version of this map, at a scale of 1 inch = about 8 miles, also is available. This more detailed map provides data on discovery date, depth, and producing horizon of individual pools, and stratigraphy. Natural gas and liquid petroleum storage areas in Ohio also are shown.

produce from this formation. A show of oil was reported from the "Franconia" (Kerbel) interval in the C & E No. 1 Recker test hole in Ballville Township, Sandusky County (Janssens, 1973). This horizon lies immediately below the Knox/Copper Ridge interval, and may be in hydraulic communication with the Knox/Copper Ridge. For this reason, permission to inject waste into the Maynardsville Formation has been denied in the past.

Only one show of gas has been reported from the Mt. Simon Sandstone in Ohio. This show was reported in the H & H Production Co. No. 1 Pohlman in Allen County (Janssens, 1973). No shows have been reported from the Rome Formation (Janssens, 1973).

There is no apparent production of oil or gas within the area in which substantial changes of pressure or fluid chemistry will occur as a result of waste injection into the Mt. Simon Sandstone at the CWM site. There is no evidence to suggest that the Mt. Simon Formation will be productive of oil or gas in the future in the state of Ohio. As long as injection is confined to the Mt. Simon interval, and the overlying beds are intact, the risk to oil and gas resources is remote. However, other strata present at the site may have undiscovered reserves present near the site. Since waste from several of the CWM wells has apparently escaped into formations that may contain oil or gas reserves, it is possible that this waste could migrate to oil or gas accumulations which may later be discovered.

The relative economic impact of the waste on an oil or gas accumulation depends on both the time of impact and on the final composition of the waste plume. The concentrations of all constituents of the plume of waste decrease with increasing distance travelled due to dispersion and resulting dilution. Some constituents will undergo alteration due to contact with native materials. If the time of travel from the injection well to the accumulation is extremely long (10,000+ years) the chances increase that the accumulation will be discovered and utilized in the interim. It is also possible that such accumulations may have little economic importance to society at that time. Although speculation on the latter possibility is beyond the scope of this study, we have estimated potential rates of regional migration in these formations in Chapter 6.

## 5.2 Ground Water

In the vicinity of the CWM site, fresh ground water can be obtained from both the surficial glacial deposits and from the underlying carbonate bedrock.

The glacial deposits at the site have been penetrated by numerous boreholes drilled for the installation of wells used for production of water and for monitoring the chemical quality of water. The depth to bedrock has been found to range from 40 to 60 feet. A glacial till unit approximately 30 feet thick directly overlies the carbonate bedrock, and is in turn overlain by a glacio-lacustrine deposit. The basal till unit has been subdivided (Bowser-Morner, 1983) into two lithologically distinct subunits: a lower unit (0 t 10 feet thick) composed of reworked bedrock material such as sand and gravel-sized clasts of limestone and gypsum, and an upper unit composed of silty clay with some sand and traces of gravel. The glacio-lacustrine surficial unit has been subdivided into two subunits also. The lower subunit is approximately five feet thick and is composed of laminated, alternating layers of clayey fine sand, clayey silt, and clay. The upper subunit is composed primarily of silty clay.

Most of the samples of the glacial materials yielded laboratory permeabilities of approximately 1 x $10^{-8}$ to 1 x $10^{-9}$ cm/sec. The generally low permeability of the glacial deposits in the near proximity of the site is reflected in the fact that most of the domestic wells in this area are completed in the underlying weathered bedrock. However, the lithologic composition of the glacial deposits varies from area to area, and thick sand deposits are found along the trends of buried channels of ancient streams. One such elongated sand deposit, oriented in a north-south direction, is embedded in otherwise clayey materials approximately 5 miles west of the CWM site.

The bedrock at the CWM site is composed primarily of limestone, dolomite, and shale. A number of stratigraphic units are included in a 550-foot thick composite rock unit known locally to drillers as the "Big Lime" (Plate 1). The Big Lime in this location is composed of (in descending order), the Tymochtee Formation, the Greenfield Formation, the Lockport Formation (Lockport also called Guelph/Goat Island/Gasport Dolomites in this area) the Rochester Shale, and the Dayton Formation. The upper surface of this sequence of carbonate rocks was exposed to preglacial weathering and erosion. Rock samples collected from boreholes at the site indicate that solutioning has taken place as evidenced by small vugs or voids and by redeposited crystals lining veins and partings. The most easily soluble mineral in the Tymochtee and Greenfield units (Salina Group) is gypsum (calcium sulfate), which occurs in thin beds as an original deposit or as an alteration of the original anhydrite. Some of the gypsum has apparently been dissolved by circulating ground water and redeposited in vugs and fissures elsewhere in the carbonate section. The dissolution of gypsum contributes to the rather elevated levels of sulfate in local ground waters.

The entire Big Lime section, extending to a depth of approximately 600 feet, should be considered to be potentially productive of fresh ground water. The deepest water production well at the site (CWM No. 1N) is completed at a depth of 200 feet. A second well (CWM No. 2) is completed at a depth of 150 feet. These wells have been tested at rates of 10 gpm and 275 gpm, respectively. The static water levels of these wells and the other monitor wells at the site range from 10 to 20 feet below ground surface. The concentration of chloride in waters from wells at the site ranges from less than 20 mg/L to over 2,000 mg/L. Concentrations of sulfate range from approximately 1,000 to 2,000 mg/L. Traces of hydrogen sulfide gas are reported from wells elsewhere in Riley Township. Some oil well records indicate that shows of gas (natural gas - methane/ethane) were encountered while drilling through the Big Lime in eastern Sandusky County.

Some area wells have been drilled to lower stratigraphic levels in the Big Lime. Several wells in the city of Fremont are over 300 feet deep and yield up to 300 gpm. These wells are apparently completed below the gypsum-bearing Tymochtee and Greenfield Formations and the waters are less highly mineralized than those at the CWM site. For example, a well drilled to a depth of 389 feet in Fremont (Supplemental Well No. 55, ODNR, 1970) produced water containing 128 mg/L sulfate and 9.0 mg/L chloride.

The entire Big Lime has been considered to be productive of fresh water since the first injection well was drilled at the CWM site. All of the injection wells employ protective surface casing set at the base of the Big Lime. The long string casings are set inside this surface casing, and both casing strings are cemented to the surface.

## CHAPTER SIX - SUBSURFACE INJECTION IN THE MT. SIMON SANDSTONE

### 6.1 General

When subsurface injection is employed as a disposal method, the paramount concern from an environmental perspective is containment of the waste at the intended depth and prevention of unwanted migration of the waste to the biosphere or to valuable underground resources such as drinking water, oil, or natural gas. The primary failure modes can be divided into two classes of concerns. The first consists of those processes that may result in local escape of injected material or native brine from the disposal formation during the operating life of the well. This may result from failure of the well itself, or failure of the geologic media to contain the pressurized liquids, during the period when pressures are increased due to injection. The second type of concern is the fate of the slug of injected fluid after the well has ceased to operate. When the artificial increases in pressure have dissipated, the movement of the slug will be influenced by natural hydrodynamic flow in the disposal zone. It would be desirable to estimate flow rate and direction of movement and possible areas of regional discharge.

In the following pages, the available data on the geologic media at the site are reviewed. The properties of the formations that are of primary concern to waste injection are emphasized. The hydraulic response of the disposal reservoir and the confining beds are reviewed in the context of waste containment, given the expected operating pressures and rates employed at this site. Finally, the ultimate fate of the injected fluid after well abandonment is examined.

### 6.2 Results of Tests of the Disposal Reservoir

The general requirements of a media to be used for disposal or storage are:

1. Sufficient permeability and porosity so that economical flow rates can be achieved at pressures which will not create hazards.

2. Native fluid of no economic value.

3. Confinement by overlying low-permeability beds to prevent escape of fluids from the reservoir.

Many of the properties of the disposal reservoir have been determined by various methods. The types of tests employed and the type of information that can be derived from each under ideal conditions are listed below:

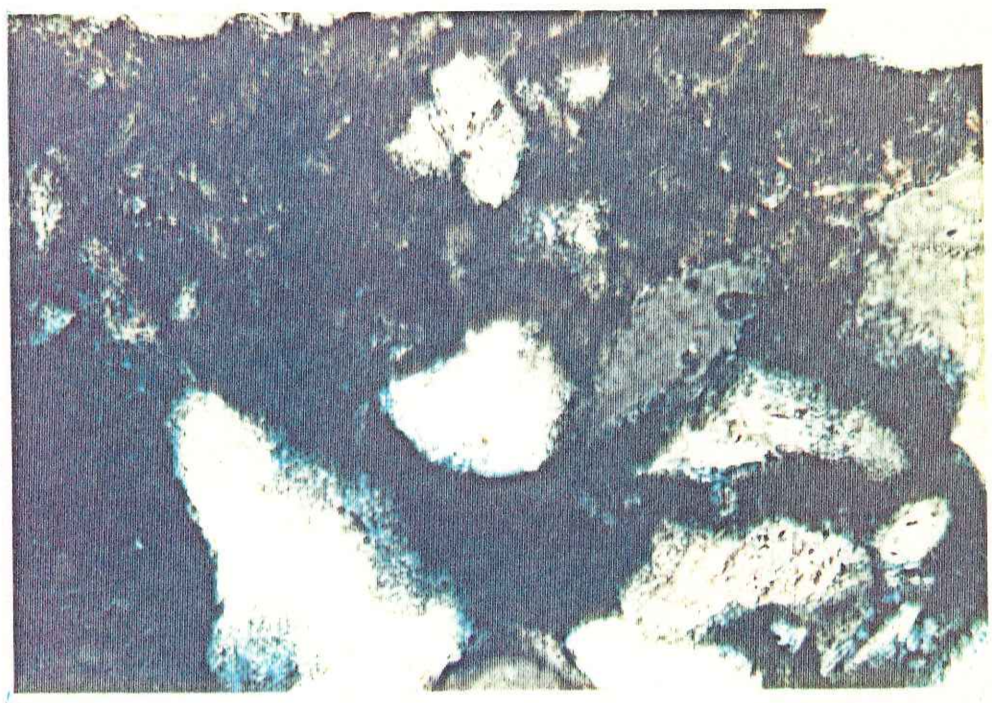
| Method | Information |
|---|---|
| Electric Logging | General Lithology and Layering Sequence |
| Examination of Core and Cuttings | Lithology |
| Testing of Core Plugs | Permeability and Porosity |
| Drill-stem Testing | Flow Capacity, Reservoir Pressure |
| Interference Testing | Flow Capacity and Reservoir Porosity - Compressibility Product (Storativity) |
| Water Analysis | Composition of Native Fluid |
| Hydrofracturing | Fracturing Pressures, Earth Stress |

The following sections describe the information that has been derived from the above procedures.

6.2.1. Core, Cuttings, and Logs: The Mt. Simon Formation has been cored at the CWM site in disposal Wells 1, 4, and 5. The cores were described by consultants to site operators, and small-diameter (1/2 inch) plugs were cut from the core at approximately one-foot intervals for measurement of porosity and permeability.

The Mt. Simon Formation consists of very fine to coarse grained sandstone. The sand is tan to reddish, poorly to well cemented, angular to subrounded with occasional thin blue to green to gray silty or shaly beds. In some horizons, the sandstone is dolomitic. The basal zone may be arkosic (fine to medium-grained "granite wash"). Original, detailed descriptions of the core can be found in the OEPA files.

Several thin sections were cut from a sample of the Mt. Simon Formation from a depth of 2,880 feet in Well No. 5 (Figures 23 and 24). The Mt. Simon in these sections consists of medium and coarse-grained subarkosic to arkosic sandstone. The sandstone is characterized by small ripple cross-laminations and shows signs of reworking by organisms. There are occasional thin layers of depositional clay. In some sections, the framework grains are 50% feldspars and 50% quartz, in others quartz is the dominant mineral. The feldspars are microcline and albite. Some of the albite grains have been partially or totally dissolved by natural ground waters. Some of the dissolution has produced large pores. Secondary minerals include garnet, zircon, epidote and magnetite, and some of these have been partially or totally dissolved, contributing to porosity. A sample of medium sandstone contained approximately 8% depositional clay and 6% diagnetic clay. The diagenetic clay is chlorite, while the depositional clay appears to be

⟼0.1 mm⟻

Figure 23.

Photomicrographs of Mt. Simon Sandstone, Well No. 5, depth 2880 ft. Upper photo in plane light, lower photo is the same view in polarized light. The upper part of each photo shows clay material that was originally deposited with the sand has recrystallized to a probable chlorite-illite mixed-layer clay material. The lower part of each photo shows clay material that has precipitated between quartz sand grains after deposition. Clay is probably chlorite.

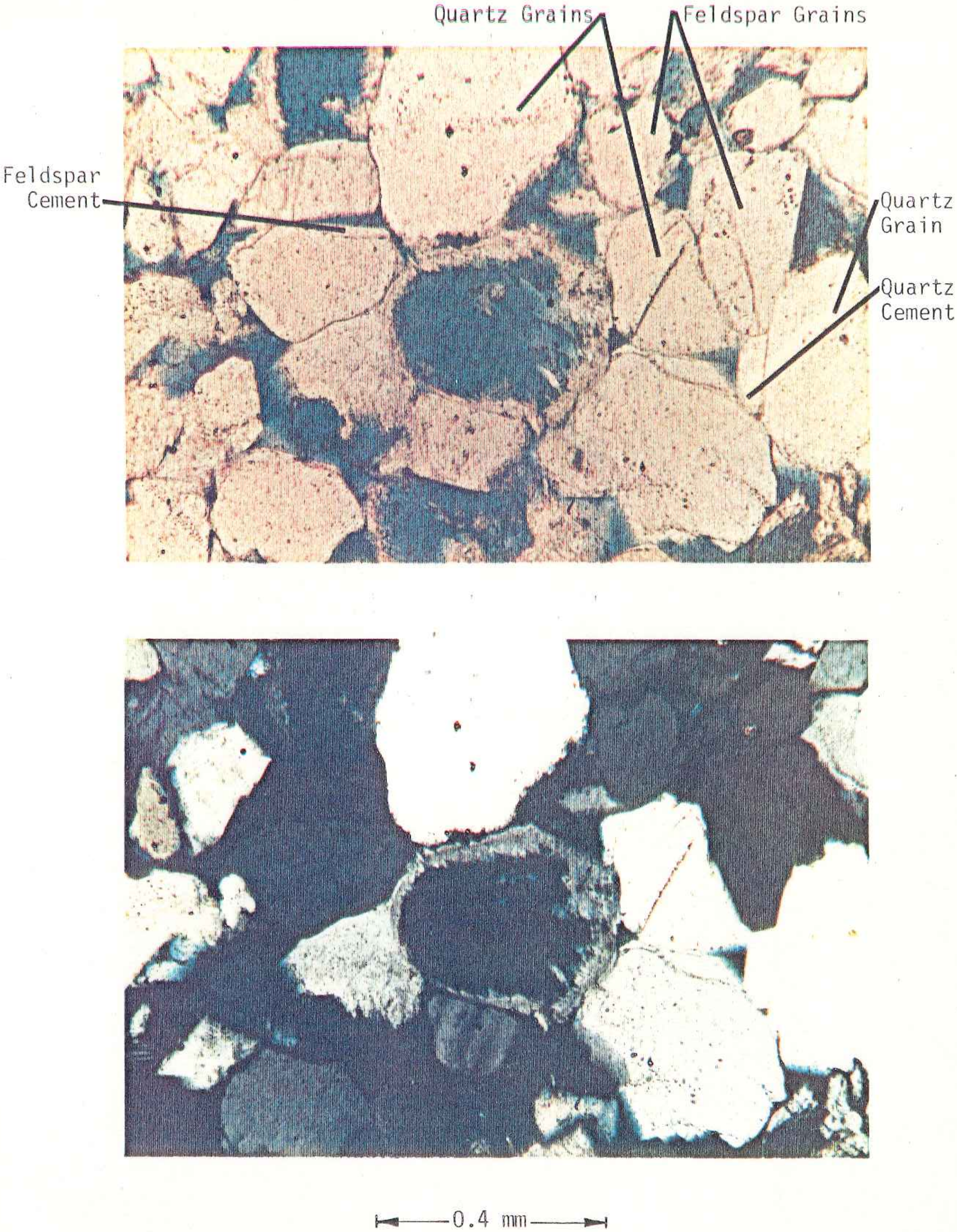



Figure 24.

Photomicrograph of Mt. Simon Sandstone, Well No. 5, depth 2880 ft. Upper photo in plane light, lower photo is the same view in polarized light. Feldspar grain in center has been partially dissolved, creating oversized pore. Pore space appears blue in upper photo due to resin impregnation of sample.

recrystallized mixed-layer illite-chlorite clay. The sandstone samples were cemented with quartz and feldspar growths between the grains. No carbonate cement was observed. However, carbonate material was detected by x-ray diffraction of samples from Well No. 4 at depths of 2,834, 2,840, and 2,888 feet. The x-ray diffraction work was done by Erco Petroleum Services. Petrographic examination of thin sections was done by the staff of the University of Texas at Austin Department of Geological Sciences.

The cores have been subjected to permeability and porosity measurements by Core Laboratories, Inc. Porosity is defined as the volume of pores or voids divided by the total volume of sample. Permeability is a measure of the flow rate through a sample divided by the pressure or head gradient imposed between the ends of the sample. Permeability usually increases in a general way with increasing porosity, but this is not always true since the degree of interconnection and tortuosity of pores is the primary controlling factor.

The tests on the core from Well No. 1 indicated a maximum permeability of 218 millidarcies (m.d.). This is equivalent to approximately 4 gallons per day per square foot (gpd/ft$^2$) in typical ground-water units. The arithmetic mean of all samples with more than 0.1 md permeability was calculated to be 37 md for 65 samples. The arithmetic mean of the measurements of porosity of these samples was 15.6%.

The tests the on core from Well No. 4 indicated a maximum permeability of the Mt. Simon Formation of 776 md. The arithmetic mean of permeabilities of 78 samples with a permeability greater than 0.1 md was calculated to be 92.6 md. Average porosity of these samples was 14.3%.

The tests on core from Well No. 5 were made with full-diameter core. The maximum measured horizontal permeability of the Mt. Simon core was 3,037 md. The arithmetic mean of the permeability of the 123 samples tested was calculated to be 55.9 md. The average porosity was 14.4%.

The zones of higher permeability within the Mt. Simon interval appear to be traceable from well to well, indicating that the primary zones of fluid acceptance are somewhat laterally continuous. These zones also appear to correlate in a general way with high porosity zones on neutron logs of the wells. Lateral continuity of individual permeable intervals suggests that the disposal reservoir, which primarily consists of the more permeable zones in the Mt. Simon, may have considerable areal extent. Lack of nearby boundaries to the more permeable zones may serve to moderate the rate of long-term pressure increases due to operation of the well field (See Section 6.4).

Laboratory measurements of permeability test only a small sample, or "plug", of rock. This sample is usually cut from a larger core, and intact rather than fissured or fractured rock is always chosen. Broken rock cannot be properly reassembled in the test apparatus in a manner which would yield laboratory permeabilities that reflect true field permeabilities of fissured rocks. For this reason, it is generally preferable to also test the entire in-place disposal reservoir at the same time by means of a drill-stem test, a fluid withdrawal test (pumping test) or a fluid injection test. Since the rate of pressure buildup due to operational injection depends on the flow capacity (transmissivity is the analogous ground-water term), which is the summation of the permeability - thickness product of the individual zones, the flow test has the added advantage of directly measuring this integrated flow capacity without the necessity of estimating the thickness of individual beds. However, a formal, reliable measurement of the flow capacity of the Mt.

Simon at the CWM site has not been made.

6.2.2 Water Analysis: Samples of native brine from the Mt. Simon Formation were recovered from Wells 1 and 4. The sample from Well No. 1 was recovered from a drill-stem test (discussed in the next section) and may be somewhat contaminated with drilling fluid. The sample from Well No. 4 was produced by air lift after the long casing was cemented and the float shoe and bridge plug were drilled out. The analyses of these samples is shown below:

| Constituent | Well No. 1 | Well No. 4 |
|---|---|---|
| Ca | 11,750 | |
| Mg | 2,250 | |
| Na | 33,500 | |
| $HCO_3$ | 55 | |
| $SO_4$ | 760 | |
| CL | 78,000 | 83,000 |
| pH | 6.0 | |
| TDS | 126,300 | |

Values shown are mg/L except pH (std. units).

The high concentration of calcium in the formation brine and the high concentration of sulfate in the waste liquid cause precipitation of calcium sulfate when the two waters are mixed. For this reason, injection of waste into the disposal wells at CWM has been preceded by injection of fresh water as a buffer between the brine and waste.

6.2.3 Drill-Stem Tests: Drill-stem tests have been conducted in the Mt. Simon Formation-Shady Dolomite in Well No. 1, in the Maynardsville-Gull River-Glenwood-Copper Ridge interval in Well No. 2, and in the Maynardsville interval in Wells No. 4 and 5.

In typical drill-stem test, a section of open borehole is isolated by packers attached to a string of empty drill pipe. A valve is opened and formation fluid flows through perforations and into the pipe, typically for a period of 5 minutes to 2 hours. The valve is closed (the formation is "shut in") and the reservoir pressure recovers from the disturbance, yielding a "build-up" test. Pressure data are typically recorded downhole by a bourdon-tube gauge and clock that are part of the test tool. The pressure data are recorded as a scribed line on a metal chart that is moved by the clock mechanism. When the tool is retrieved, the chart is removed and pressure and time data are read from it with special optical equipment.

The method of analysis of drill-stem test data is based on the solution to the problem of transient radial flow from a line source in a homogeneous, isotropic, confined reservoir of infinite areal extent (Theis, 1935). The solution that describes pressures during the recovery (buildup) period is obtained by superposing a sink at the location of the source at the moment of shut-in (Theis, 1935; Horner, 1951). A plot of pressure versus log time will ordinarily form a straight line at long times if the above assumptions are met.

The plot for the drill-stem test at Well No. 1 is shown in Figure 25. The permeability-thickness product (termed flow capacity in the petroleum industry; analogous to transmissivity in the water industry) is proportional to the slope of the straight line and to the flow rate. The flow rate is calculated by determining the length of the drill pipe that was filled up during the flow period, the inside diameter of the pipe, and the time allowed for flow. The flow capacity was calculated to be 8,000 md-ft. in this test. The zone open to the flow test was the entire open hole section below a depth of 2,757 (KB) or 2,746 (ground level datum). Although the Shady Dolomite is considered to be a confining layer, it contains thin layers of sandstone, and the dolomite itself

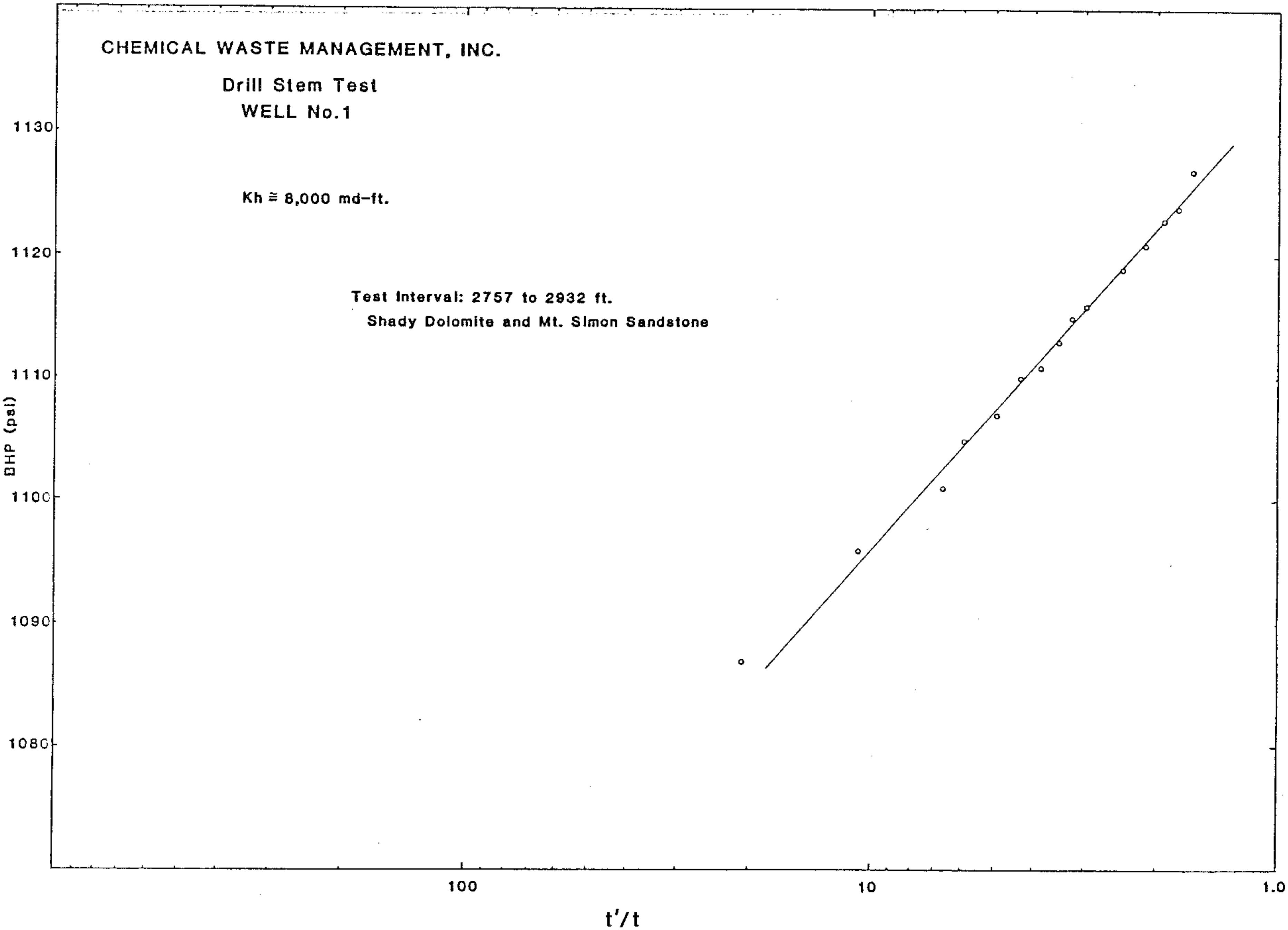



Figure 25. Drill Stem Test

is characterized by thin horizons whose permeability was measurable in tests on the core from Wells No. 4 and No. 5. Therefore, some zones having horizontal permeability within the Shady Dolomite were probably contributing to the flow capacity test (and fluid sample) conducted primarily to test the Mt. Simon. The static reservoir pressure obtained by extrapolating the trend shown in Figure 25 to "infinite time" (log t'/t = 0) was 1,132 psi. Correcting this pressure for the difference in depth between the gauge and the center of the Mt. Simon formation yields an original native pressure of 1,181 psi. The error in this type of gauge typically may range up to 10%.

Using this same method, the following flow capacities were obtained in the drill-stem tests conducted in other wells.

| Well | Formation(s) | Interval (ft.)(KB) | Flow Capacity (md-ft.) |
|---|---|---|---|
| 1 | Shady Dolomite - Mt. Simon | 2757-2932 | 8,000 |
| 2 | Gull River, Glenwood, Copper Ridge, Upper Maynardsville (Incl. Knox Unconformity) | 2293-2484 | 13,900 |
| 4 | Maynardsville (Part) | 2524-2600 | 5,000 |
| 5 | Maynardsville (Full) | 2396-2600 | 11,000 |

The test of Well No. 2 included only the upper 33 feet of the Maynardsville Sandstone. Most of the flow capacity is probably due to the Gull River, Glenwood, and Copper Ridge Formations and the Knox Unconformity, which occurs at the base of the Glenwood Formation.

6.2.4 Interference Test: An interference test was conducted in September of 1983 for the purpose of measuring the hydraulic properties of the Mt. Simon Formation. Although a drill-stem test had previously been conducted at Well No. 1 (see preceding section), the test had included a part of the overlying Shady Dolomite. The fraction of the measured flow capacity that was contributed by the Shady Dolomite is unknown. The interference test was designed to measure the properties of the Mt. Simon Formation alone. These properties include flow capacity and porosity-compressibility product, as well as the efficiency of the injection well.

The test was performed by injecting fresh water into Well No. 6 and measuring the pressure changes in Wells No. 6 and No. 2 using pressure transducers and digital measurement equipment. However, these two wells were subsequently subjected to casing tests and both were found to be open to formations other than the Mt. Simon. Well No. 6 was found to be leaking through a corroded interval between the depths of 2,682 and 2,728 feet. The geologic unit in this interval is the Rome Sandstone. Well No. 2 was found to be leaking in the depth interval between 2,423 and 2,500 feet. The geologic unit present in this interval is the Maynardsville Sandstone (Kerbel Formation). Therefore, the test conditions did not conform to the configuration that is necessary in order to apply the standard techniques of analysis. The result is that there is no assurance that the calculated parameters represent the Mt. Simon Formation.

The data collected at Well No. 6 after pumping stopped were analyzed using the method described in the last section. A "Horner plot" of the data is shown in Appendix B. The resulting flow capacity was 3,100 md-ft. This flow capacity may represent the Mt. Simon Sandstone, the Rome Sandstone, or portions thereof. The value appears to be too low to represent the full, combined flow capacity of both intervals. However, this value is not dissimilar from those obtained by analysis of falloff data collected after shutdown of newly repaired wells, as described in the next section.

The data collected at Well No. 2 do not form an analyzable trend. Therefore, a measured value of the porosity-compressibility product has not been obtained for the Mt. Simon Sandstone. This parameter was to have been used to calculate the expected radius of influence of the wells at the CWM site. Instead, an assumed value was employed for these calculations. The assumed value was based on the average porosity derived from tests on core material, and on a "typical" compressibility value based on empirical measurements of other sandstone units in other regions. The results of the reservoir calculations are found in Section 6.4.1.

<u>6.2.5 Wellhead Pressure Falloff</u>: Additional data for the estimation of formation permeability was obtained when wells were turned off ("shut in") prior to integrity testing or because of power failure or other causes. The data consists of wellhead pressure versus the time since the well was shut in. The data were collected by the well operators. Since the pressure in the Mt. Simon Formation has been elevated by injection of waste, the wells are completely full of water for many hours after shut in. During this period before the free liquid surface falls below ground level as the formation pressure dissipates, it is possible to read pressures with a gauge mounted on the wellhead. These tubing-head pressures are directly proportional to bottom-hole pressures, being less than the latter by the hydrostatic pressure of the column of liquid in the tubing. The rate of decline of the surface pressures is therefore the same as the rate of decline of bottom-hole pressures, so this trend can be analyzed by standard methods to yield an estimate of flow capacity. Plots of these data are shown in Appendix B.

The results are summarized below:

| Well | Date Shut In | Calculated Flow Capacity (md-ft) |
|---|---|---|
| | (Before Well Reconstruction) | |
| 1A | Sept. 19, 1983 | 2,000 |
| 1A | Oct. 6, 1983 | 3,200 |
| 3 | Aug. 16, 1983 | 8,700 |
| 4 | Sept. 19, 1983 | 2,900 |
| 4 | Oct. 27, 1983 | 2,900 |
| 5 | Sept. 19, 1983 | 3,590 |
| 5 | Nov. 7, 1983 | 3,800-5,100* |
| 6 | Nov. 7, 1983 | 1,700-2,000* |
| | (After Well Reconstruction) | |
| 1A | Jan. 22, 1984 | 2,500-3,400* |
| 3 | Jan. 22, 1984 | 2,370-2,950* |

*Value depends on choice of fit of straight line to data.

The data collected from leaking wells that had not been repaired (1A, 3, 4, and 6) may represent the Mt. Simon Formation plus part of some of the formation into which leakage occurred. Some portions of formations into which leakage occurred may have been plugged or not open to the leak. In most cases, the values derived from the data collected at these wells are similar to those derived from the repaired wells. (Well No. 3 may be an exception and may represent the flow capacity of Mt. Simon plus part of the Maynardsville Formation).

The data from the repaired wells suggests that the flow capacity of the Mt. Simon Formation is approximately in the range of 2,500 to 3,500 md-ft. A value of 3,000 has been used to project the future distribution of fluid pressures in the Mt. Simon Formation that have been calculated and reported in a later section.

6.2.6 Hydraulic Fracturing: The technique of intentional hydraulic fracturing was developed by the oil and gas industry to increase the efficiency of fluid-withdrawal wells. Wells with sand-filled fractures in the adjacent reservoir rock ordinarily produce at a higher flow rate for any given pressure at the wellbore compared to an unfractured well.

The pressure at which fractures initiate and grow and the geometry of the fracture have critical importance to both petroleum production and waste injection projects. Use of heavy muds during the drilling of oil and gas wells may cause accidental fracturing and loss of circulating drilling fluids, resulting in possible loss of control of fluid pressures at the bit. Excessive vertical extension of purposely induced fractures into adjacent low-permeability strata may result in unwanted migration of oil or gas. If injection wells are fractured, vertical height must be controlled to protect the confining beds. Also, during operation, injection pressure should not be allowed to approach the fracture-extension pressure.

Intentional hydraulic fractures are created by pumping specially formulated fluids down the well at relatively high rates and pressures. The rock formation fractures ("breaks down") since the applied stress exceeds the in-situ stress plus the tensile strength of the rock. Ordinarily, granular material ("proppant") such as sand is added to the fluid and pumped into the growing fracture to keep it open after the frac job. The grain size of the sand is chosen to provide a highly permeable pathway to or from the well for the fluids that will later be produced or injected.

The threshold pressure for fracture extension is approximately equal to the smallest component of earth stress within the rock formation. Except at very shallow depths, this minimum principal stress is oriented horizontally, so fractures will tend to extend in the direction of least resistance, in a vertical plane oriented normal to the direction of the minimum compressive in situ stress. The magnitude of this stress can be measured during a carefully controlled fracture treatment, because when flow is stopped, fracture extension ceases and the bottom-hole pressure briefly falls to the level just required to hold the fracture open against the in situ stress. This measured pressure is termed the instantaneous shut-in pressure (ISIP) can can be used as a guide to the safe operating pressure for a field of injection wells, since the pressure required to fracture a disposal reservoir can be used as an approximate guide to the pressure required to fracture the confining beds.

Although the fracture-extension pressure in dolomite confining beds may be somewhat different than the extension pressure in sandstone reservoir rock, since the two rock types have different elasticities, a pressure value measured in sandstone can be used as a guide or rough approximation to the critical value in dolomite.

The wells at the CWM site have been stimulated by several methods. A propped fracture was created at Well No. 5 on October 13, 1982. An instantaneous shut-in pressure was recorded at the surface at the conclusion of this treatment, after 45 minutes of pumping fluids into the well. The recorded pressure was approximately 800 psi. The fluid column contained 9 lb./gallon sand, resulting in a bottom-hole pressure at 2,850 feet of approximately 2,590 psi. Allowing for an estimated formation pressure buildup of 200 psi due to leakoff of frac fluid, the ISIP at the center of the Mt. Simon Formation would have been approximately 2,300-2,400 psi (.81-.84 psi/ft.). The actual amount of pressure buildup that should be allowed for is not known.

The other wells at the site have been chemically stimulated by injection of acid to dissolve some of the native mineral cements or residual drilling mud. In most instances, the service records of these acid treatments state that the sandstone reservoir rock was fractured. The maximum pressures reported for acid jobs or injection tests of these wells are:

| Well | Procedure | Surface Pressure (psi) | Date |
|---|---|---|---|
| 1 | Injection test | 3,300 | 4/09/76 |
| 2 | Injection test | 1,350 | 10/27/76 |
| 3 | Acid job | 1,550 | 11/08/76 |
| 4 | Injection test | 1,600 | 11/23/77 |
| 5 | Acid job | 1,900 | 5/30/81 |
| 6 | Acid job | 2,500 | 6/26/81 |

There was no record of elevated pressures being applied at Well 1A.

Assuming the fluids had the same specific gravity as fresh water, the bottom hole pressures would range from approximately 2,562 to 3,112 psi. The corresponding pressure gradients are .915 to 1.11 psi/ft. at 2,800 feet.

These pressures do not provide an accurate measure of the in-situ stress because:

1. The reported pressure is a flowing surface pressure. It is preferable to obtain a shut-in bottom-hole pressure to eliminate the uncertainties of both density and rate-dependent frictional losses between the surface and the bottom of the hole.

2. The above pressures recorded during acid jobs are generally "breakdown" pressures, which are ordinarily higher than the ISIP or in-situ stress because of the tensile strength of unfractured rock.

These data reflect the fact that several of the wells at the site have been hydraulically fractured, but the fractures were not propped open, in the course of chemical stimulation treatments. The maximum operating pressure limit at CWM should, therefore, be based on the fracture extension pressure (ISIP) and not the breakdown pressure.

Well No. 4 was reconstructed during December 1983. An agreement was reached between CWM and OEPA that this well could be hydraulically fractured in order to accomplish two objectives. OEPA desired to make an accurate management of the in-situ earth stress in the Mt. Simon Sandstone at the site in order to determine if the limit OEPA has placed on operating pressures was appropriate. CWM desired to fracture the well in order to increase injectivity. Since fracturing of the confining bed (Shady Dolomite) was to be prevented, a test was designed by service company engineers in order to establish the fracture height that might be expected during an actual fracture treatment of this well.

The test consisted of the following procedures:

1. A notch was created in the open hole section (Mt. Simon) by hydra-jetting with a mixture of water and sand. The hydra-jet tool consists of nozzles mounted on work tubing through which an abrasive slurry is injected. This procedure was used on the basal eight to ten feet of the Mt. Simon Formation in an attempt to induce initiation of a single test fracture at this depth.

2. Using ten lb/gallon brine (viscosity approximately 1.0 cp) with radioactive tracer material added, fluid was pumped into the well in order to initiate a fracture and measure both the fracturing pressure and the instantaneous shut-in pressure (ISIP).

It was hoped that a gamma-ray logging tool could then be used to determine the interval of primary fluid entry and therefore define the length of the fractured interval, yielding the fracture height. Although the compass orientation of the notch was not known, it was hoped that the fracture would initiate at the notch, even though it was recognized that the notch might not lie in a plane that is perpendicular to the least principal earth stress and that the fracture would probably realign to that direction some distance from the borehole.

During this second procedure, the pressure was raised slowly and ultimately reached 1,600 psi, but no definite indication of fracture initiation was observed. Pumping was stopped and the gamma tool was run run in the open section of borehole. The gamma log indicated that the bulk of the fluid was entering the notched area, with a relatively minor flow into the upper part of the Mt. Simon formation. Since a definite indication that a fracture had been created was not observed, no fracture height vs. flow rate data were obtained, and a decision was made not to stimulate this well with a propped fracture.

Since a valid measurement of the fracture extension pressure has been not made at this site, specifications of the maximum safe injection pressure at this site can be based only on data obtained at other sites in the region.

Data specific to the Shady Dolomite is apparently nonexistent. Data specific to the Mt. Simon Formation is not abundant since few wells have been drilled to this objective in the northwestern part of the Appalachian Basin. Most of the available data on fracturing pressures comes from oil wells drilled farther east in a trend or fairway that extends from Cuyahoga County to the southern border of Ohio in Lawrence and Scioto Counties. It has been found by the service companies that average ISIP gradients of approximately 0.733 to 0.75 psi/ft. have been used to treat fractures in the Clinton Sand units (Clifford, 1975). Clifford (1975) noted that most of these tests were performed after withdrawal of oil had lowered the fluid pressure in the Clinton, and stated that the fracture gradient of "undisturbed" Clinton sandstone would probably be greater than 0.75 psi/ft. The depth of the Clinton in this trend ranges from approximately 2,500 to 7,000 feet.

Two other injection wells in Ohio completed in the Mt. Simon have reportedly been fractured. The Calhio No. 1 in Lake County was fractured at a pressure gradient of 0.77 psi/ft. The Kerbel (Maynardsville) section was fractured at 1.25 psi/ft. In the U.S.S. Chemicals well in Scioto County, the Mt. Simon was fractured at a pressure gradient of 1.24 psi/ft., while the instantaneous shut-in pressure converts to a gradient of approximately 0.68 psi/ft.

The data from the Clinton Sandstone fracture jobs suggests that the gradient of 0.75 psi/ft. may be a realistic gradient for Ohio. The data from the Mt. Simon Sandstone fracture jobs is limited and variable, but suggests that the true value for the Mt. Simon may lie between 0.68 and 0.77 psi/ft. The inconclusive data from Well No. 5 at the CWM site suggests that the value may be as high as 0.8 psi/ft. at the site. Accurate determination of the true value at this location would require that a carefully controlled fracturing test be performed on in situ Mt. Simon Sandstone. However, the test conducted at Well No. 4 was unsuccessful, and it is not certain that attempting this procedure at other wells would be successful.

If the fracture gradient at the CWM site is 0.75 psi/ft., a maximum surface injection pressure can be calculated that would correspond to this value. The bottom-hole pressure required to extend fractures would be:

$$BHP = (0.75)(2,800) = 2,100 \text{ psi}$$

If the wellbore is full of waste with a specific gravity of 1.07 or 1.08, the static surface pressures would be:

$$THP = 2,100 - (2,800)(.433)(1.07) = 802 \text{ psi}$$
$$THP = 2,100 - (2,800)(.433)(1.08) = 790 \text{ psi}$$

This pressure has been exceeded several occasions during past operation of the wells. The originally specified limit of 840 psi/ft. was based on a fracture pressure gradient of 0.75 psi/ft. and a waste specific gravity of 1.04. It is not certain, however, that the true value of the fracture gradient is 0.75 psi/ft., due to the uncertainties listed above. However, after waste is injected into the Mt. Simon and the reservoir pressure increases, the fracture gradient and safe operating pressure will increase also.

## 6.3 Confining Beds

6.3.1 General: The means by which injected waste may travel from the intended disposal zone to undesirable areas such as the land surface or underground sources of drinking water generally fall into two categories. The first category includes processes that may result in upward escape at or near the site of the injection well during the operating life of the well. This may be due to failure of the well itself, or failure of the geologic media to contain the wastes. This is of primary concern during the period when fluid pressure in the receiving formation is increased due to injection. The second category includes the process of long-term regional migration. When the elevated pressures due to injection have dissipated, movement of the slug of injected liquid will be influenced by natural, regional circulation in the sedimentary basin. This second category is discussed in Section 6.4.3.

Upward migration is ordinarily controlled by the geologic strata that overlie the disposal zone. Upward migration is generally more likely to occur in the area relatively near the well than at a great distance from a well, since the imposed increase in pressure is greatest at the well. Injection wells should be engineered and built to ensure that the well structure is competent and secure and that migration behind the casing though the cemented annulus is prevented. The well should be periodically tested so that continued integrity is assured. Well integrity is discussed in Part A of this report. Other processes of upward migration are discussed below.

6.3.2 Artificial Penetrations: Upward migration through the geologic media in the vicinity of a disposal well may occur through either artificial or natural openings. Artificial passages through the confining beds occur primarily in the form of abandoned, improperly plugged boreholes. In some areas, this is a serious problem due to the great numbers of boreholes drilled to the disposal zone. The problem is compounded if the boreholes were drilled many years ago when standards of record keeping and well plugging were not as high as current standards. An abandoned borehole may be reentered and properly plugged if its location is known. Undocumented boreholes exist in some areas. A critical area surrounds any injection well where increased pressures in the disposal zone may provide the energy necessary to move waste or brine up through unplugged boreholes to the land surface or to exit points at the level of ground-water resources. The area surrounding the injection well where the pressure in the disposal zone is high enough to cause such movement has been termed the "area of endangering influence".

Requirements for a permit to inject wastes normally include a search of drilling permits and plugging records within this area. The availability of data for this type of search was evaluated by URM.

Records of oil and gas wells in Ohio are maintained by the Ohio Department of Natural Resources (ODNR) in Columbus. The Subsurface Geology Section of the Division of Geological Survey of ODNR maintains a file of over 158,000 "scout" cards containing data on exploration boreholes and producing wells. The scout cards are filed by county and township. An inspection of these files by URM suggested that in Sandusky County, few boreholes have been drilled to the top of the Mt. Simon Formation. Most historical drilling activity was targeted on the Trenton Formation. The Trenton lies at a depth of approximately 800 to 1,400 feet in the vicinity of Riley Township. The files contain approximately 200 scout cards for wells drilled to the Trenton in Sandusky, Riley, Rice, Ballville, Townsend, Greencreek, and York Townships in Sandusky County. Most of these were drilled between 1890 and 1910. The cards were transcribed by ODNR personnel from oil company records, thus there are probably many more wells that were drilled by small, no longer extant companies. Therefore, even though no scout cards record such wells in Riley Township, it is possible that some of this shallow drilling may have been near the CWM site. However, none of the scout cards note drilling below a depth of 1,450 feet. It is probable that few exploratory holes were drilled to the Mt. Simon in this era due to the considerable extra expense of drilling to that depth and the great likelihood of failure since no shows of oil and gas had apparently been reported for any sub-Trenton rocks at that time. The DNR files contain records of only one well in the townships surrounding the CWM site that was drilled below the Trenton horizon before 1960. The Montgomery No. 1 Hetrick was drilled to the Precambrian basement rocks in Section 30, Rice Township in 1933 (drilling completed in 1936). This site is located approximately 11.5 miles northwest of the CWM site.

Since 1965, the Oil and Gas Division of ODNR has been a separate entity within the Department, and record keeping since that date is considered to be good, according to personnel of the Subsurface Geology Section. All operators are required to submit a notification of intent to drill an exploration hole or well to the Oil and Gas Division within 30 days of initiation of drilling. The notification is routed to the Subsurface Geology Section of the Division of Geological Survey and the information is used to make a scout card. When a well is plugged and abandoned, the operator sends notification to the Oil and Gas Division, which routes a copy to Subsurface Geology for updating of the scout card.

The scout cards indicate that less than a dozen wells that have been drilled since 1960 in eastern Sandusky County. Those located within Riley, Townsend, Greencreek, and York townships are shown on Figure 26. There are no wells recorded for Greencreek and York Townships. The records indicate that the wells shown on Figure 26 have all been plugged.

6.3.3 Natural Barriers to Upward Migration: The geologic unit that directly overlies the Mt. Simon Formation at the CWM site is the Shady Dolomite, also known as the Lower Rome Dolomite. This unit is approximately 60 feet thick and is of very fine to medium-fine grained, gray to cream to light brown dolomite with up to 5% of the interval composed of thin interbeds of fine to coarse-grained sandstone. The dolomite has a pseudo-oolitic structure and contains pyrite crystals.

A thin section was cut from a core sample of Shady Dolomite from a depth of 2,787 feet in Well No. 5. Photographs of this thin section

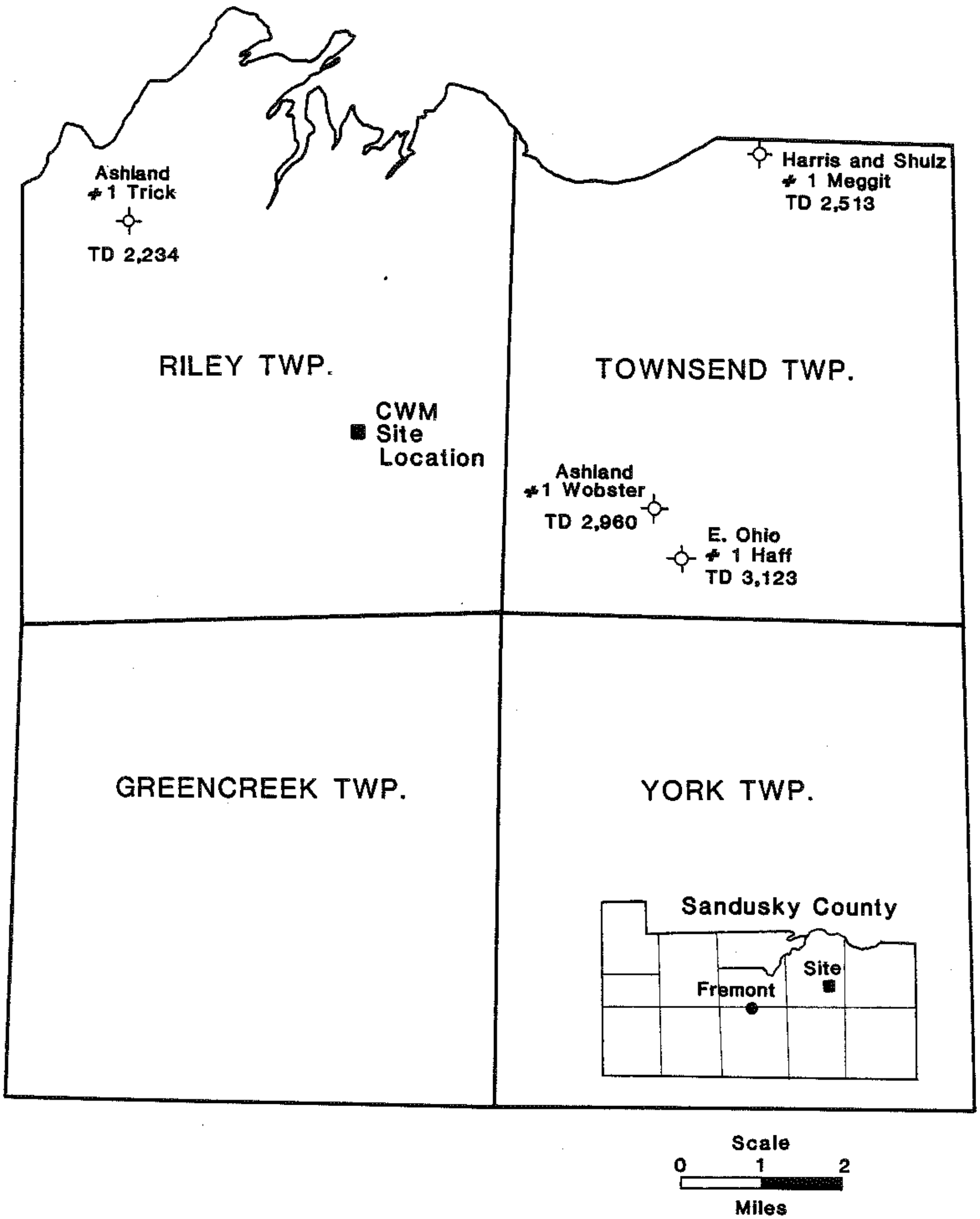
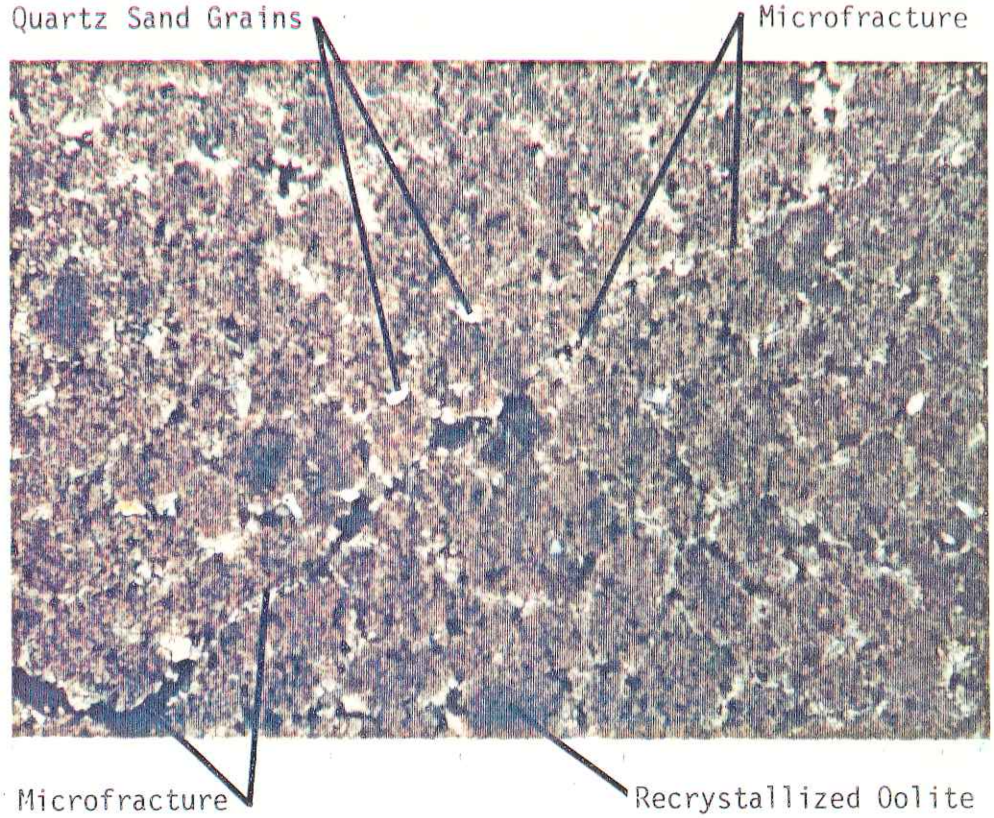



Figure 26. Wells drilled to the top of the Mt. Simon Formation or below in eastern Sandusky County.

appear in Figures 27 and 28. The Shady Dolomite, in this thin section, was apparently originally composed of oolites of calcite with an average diameter of approximately 0.4 mm. There are minor amounts of shell fragments and siliclastic sand. The oolites have been recrystallized to a finely-crystalline dolomite mosaic. Almost all the original porosity has been lost due to precipitation of dolomite cement. The existing pores are mostly in the original interoolitic areas, and have been much reduced in size due to precipitation of cement. Other scattered pores were apparently originally small shell fragments. Existing pores do not appear to be interconnected. Microfractures appear to have been partially filled by dolomitic cement. The microfractures appear to be less than 0.1 mm wide where they are open and unfilled.

Core samples display small (1 cm) vugs (voids) at several horizons, though there are many intervals that contain no apparent vugs. The vugs do not appear to be interconnected. Some of the core samples had measurable permeability as measured in laboratory tests. The majority of core plugs from the Shady Dolomite, however, were found to have permeabilities and porosities below the level that was measurable by laboratory apparatus (0.1 md permeability and 3% porosity by Core Labs, Inc., and 0.01 md permeability by Erco, Inc.). Therefore, the Shady Dolomite Formation as a whole apparently has nonhomogeneous porosity and permeability. The appearance of the core material suggests that the dolomite is composed of a few thin layers of moderately permeable (1 to 1,500 md by Core Labs, Inc.) dolomite and sandstone separated by thicker layers of relatively low permeability (<0.01 md) dolomite.

Some of the permeable layers in the Shady Dolomite may have contributed fluid to the drill-stem test conducted in Well No. 1. The measured flow capacity in this test was 8,000 md-ft. The actual fraction of this flow capacity that represents the Shady Dolomite is unknown.




⊢1 mm⊣

Figure 27.

Photomicrograph of Shady Dolomite in thin section, Well No. 5, depth 2787 ft. Microfracture extends from lower left corner to upper right corner of photo. The fracture is mostly filled with dolomite crystals. Typical fracture width is less than 0.1 mm. The photograph on the following page is an enlargement of this view.

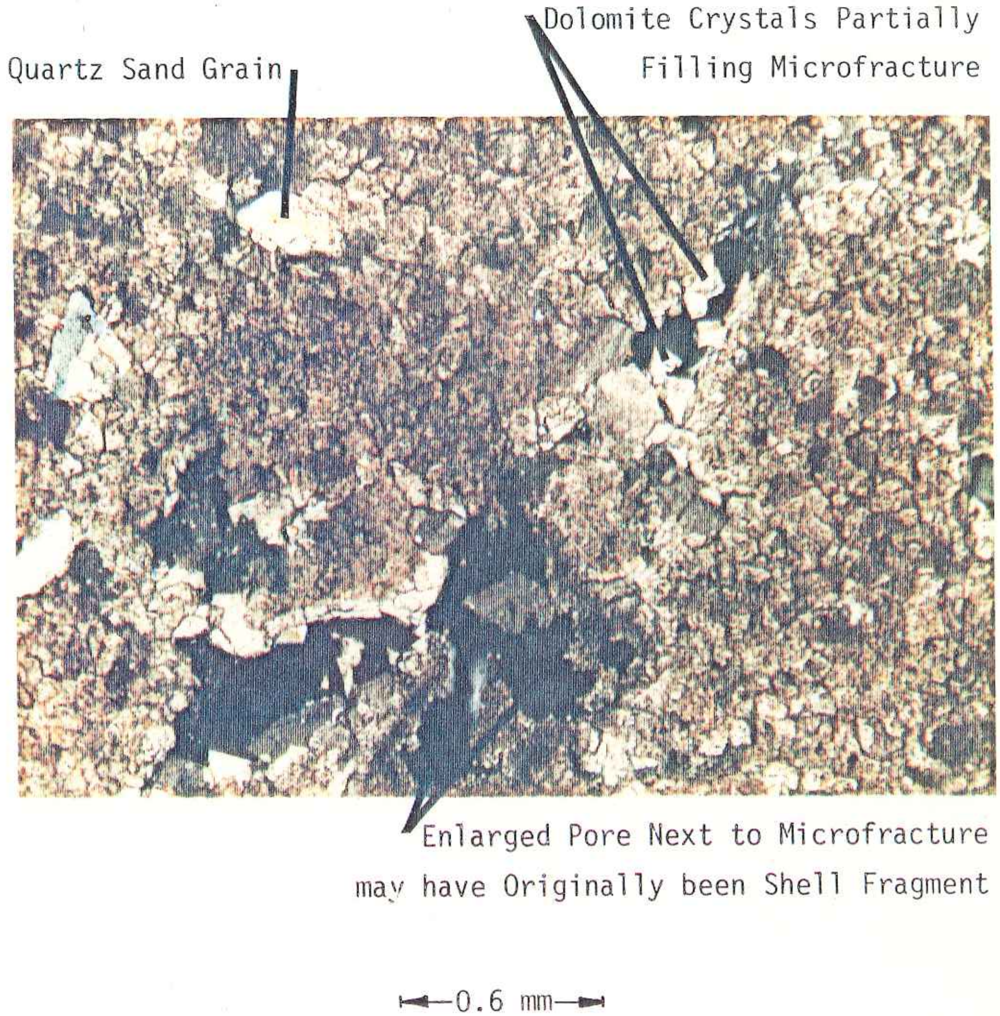



Figure 28.

This enlargement of the preceeding photomicrograph shows both fracture porosity and intergranular porosity. Both have been partially filled by dolomite crystals that formed after the pores formed. Other scattered pores do not appear to be interconnected.

Some pieces of the Shady Dolomite core material were broken. It is estimated that approximately 3 to 5% of the total length of Shady core was in this condition, while the rest of the material was intact, full-diameter core. The surfaces of these vertically oriented partings are not visibly discolored, altered, recrystallized, or slickensided. As mentioned previously, the microfissures are visible in thin sections and appear to be partially filled with dolomite crystals. Some of the unbroken cores contain what are apparently microfractures, visible as thin linear features on the face of the core. These fractures are probably well cemented by dolomite crystal growth so that the rock remains intact when removed from the core barrel. One unusual feature of the partings is that they appear to occur only in the part of the Formation that is composed of dolomite. Several of the partings terminate at sandstone-dolomite contacts and do not extend into sandstone. Termination of fissures at sandstone/dolomite boundaries may indicate that there are differences in elastic properties or tensile strength between the two rock types.

The Shady Dolomite apparently extends throughout the area in northeastern Sandusky County which elevated pressures have occurred and will occur in the Mt. Simon Sandstone as a result of waste injection. The Shady Dolomite is present for several tens of miles to the south and east of the CWM site (Janssens, 1973) (see Plate 1). The dolomite thins westward and in northwestern Sandusky County, at the McGuire No. 1 Kerbel well, it has begun to grade into sandstone. Farther west, the Shady Dolomite interval becomes increasingly sandy as the overlying Rome Sandstone thickens and begins to occupy more and more of the Shady section. In western Ohio and eastern Indiana, the Rome Sandstone/Shady Dolomite interval (Middle and Lower Rome of Janssens, 1973) grades entirely into the siltstone and very fine sandstone of the Eau Claire Formation.

The possibility that structural faults may have created passages through the confining beds at the CWM site was evaluated. Faults may allow passage of injected waste water if they have not been sealed by later deposition of minerals. One method that can be used to detect faults is to make a structural contour map of a selected geologic marker horizon that is easily located on electric logs of boreholes. The most common type of marker would be a point on the log (corresponding to a particular depth in the borehole or well) where there is an abrupt lithologic change from one layer to another, such as the bottom of the Shady Dolomite and the top of the Mt. Simon Sandstone. Since the tops of sedimentary formations typically were originally flat, horizontal surfaces, present deviations from these conditions indicate that structural movement has taken place since the formation was deposited.

For example, the regional structure map of the Mt. Simon Formation (Figure 18) shows that major regional arches and basins have formed since the formation was deposited. In order to determine the local structure and to evaluate the possibility that faulting may be present at the CWM site. Local structure maps were made of the top of the Mt. Simon Formation and the top of the Trenton Limestone using electric logs of the injection wells. The maps are shown on Figure 29. The maps indicate that the formations dip gently eastward, as expected based on regional structure maps. The dip is approximately 30 feet per mile on both regional and local maps. There are no apparent major differences in elevations of marker beds between wells that would suggest the presence of major faults.

The Shady Dolomite forms the primary barrier to upward migration, but several other geologic strata that occur between the disposal zone and shallow ground waters offer additional barriers. The sequence of beds above the Shady Dolomite is composed of alternating dolomite, shale

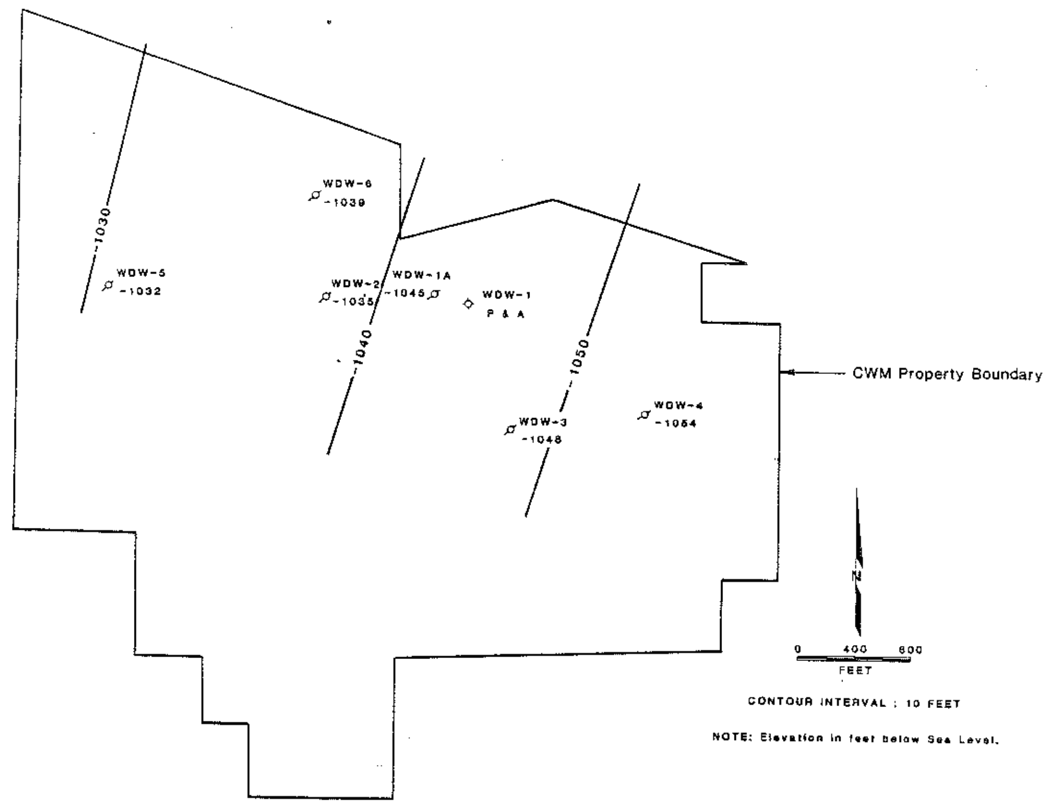



**Figure 29a. Structure Map on Top of the Trenton Limestone Formation.**

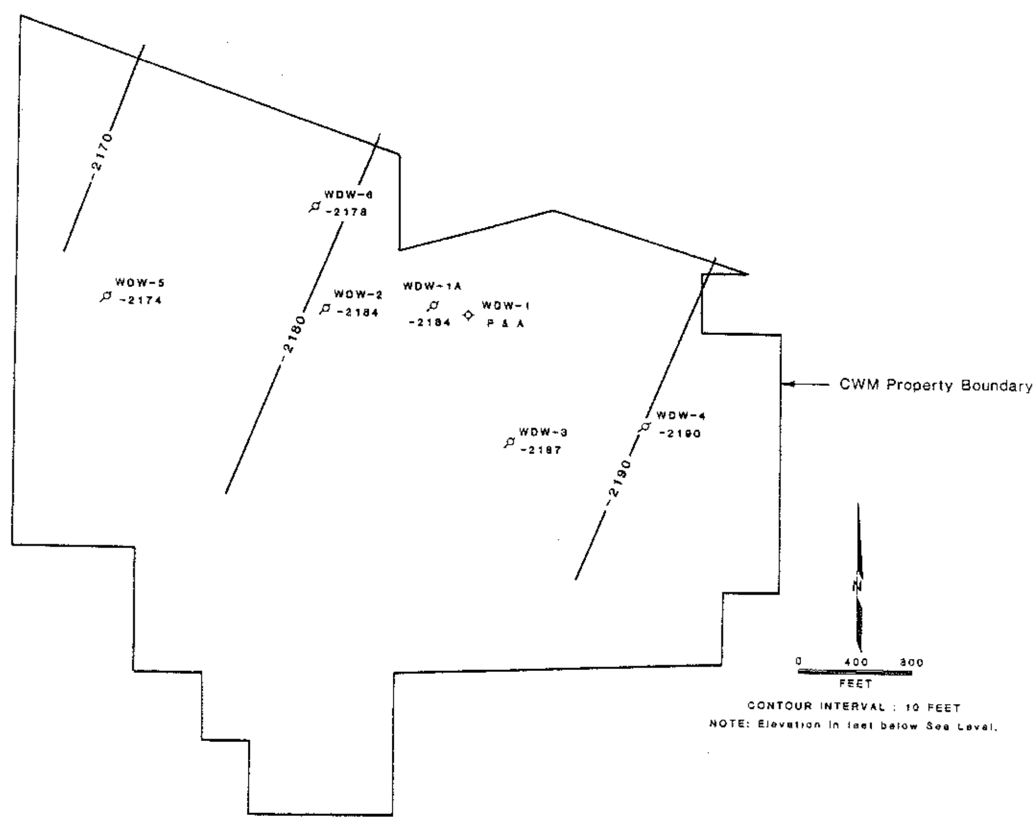



**Figure 29b. Structure Map on Top of the Mt. Simon Formation.**

and sandstone (Plate 1). Above this, a thick section of shale and dolomite (Reedsville/Black River interval) separates the freshwater-bearing Big Lime from the basal group of sandstones (Maynardsville, Rome, and Mt. Simon). The dolomite and shale beds should have relatively low permeability. Scout cards of exploratory wells drilled in eastern Sandusky County by the cable-tool method indicate that there was no inflow of fluid in these holes until they were advanced below the thick shale and dolomite section to the level of the Knox Unconformity, which is found at a depth of approximately 2,360 feet at the CWM site. The holes were drilled "wet" below that depth. As a general rule, all sediments below the water table are fully saturated with water. Drilling of "dry" holes through the interval between the Big Lime and the basal sandstones indicates that the Reedsville Shale and Black River Limestone have relatively low permeability and will not yield significant quantities of water to an open borehole. While this does not mean that these beds are totally impermeable, it does suggest that high-permeability lenses of sandstone, layers of vuggy porosity, or major faults have not been encountered in the thick Reedsville/Black River section by drilling in eastern Sandusky County.

In the part of the basal zone between the top of the Shady Dolomite and a depth of approximately 2,480 feet, the arrangement of relatively low-permeability dolomites and shales alternating with moderate-permeability sandstones provides a hydraulic barrier to continued upward migration of any waste that might flow across the Shady Dolomite through possible uncemented fissures or other natural imperfections. (Flow through intergranular porosity in the Shady Dolomite would be insignificant, as discussed in Section 6.4.1). Injection of waste creates elevated levels of hydraulic head in the Mt. Simon beneath the Shady Dolomite. The existence of normal, undisturbed head levels in the Rome Sandstone above the Shady Dolomite results in a significant upward-directed hydraulic gradient across the confining bed. Wastes that were to reach the top of the dolomite and enter the Rome Sandstone would then begin to flow horizontally in the sandstone toward surrounding areas of lower head, since the permeability of the sandstone would be significantly greater than the permeability of the next overlying dolomite, the Rome Dolomite. The Rome and Maynardsville Sandstones therefore provide secondary and tertiary protective barriers to upward migration by furnishing beds in which heads that might drive further upward flow would be dissipated. Dissipation of hydraulic head below the thick Reedsville/ Black River low-permeability interval would virtually assure that no driving force is available to cause upward flow across these beds. Therefore, the prevention of contamination of shallow ground water is not solely dependent on the measured and inferred properties of the Shady Dolomite.

The permeability of intact core plugs of the Shady Dolomite has been measured and found to be less than 0.01 millidarcy. One way to indirectly measure the approximate order of magnitude of the vertical permeability of the in-situ Shady Dolomite zone is to attempt to calculate the amount of leakage through this bed that has already occurred as a result of the past injection at this facility. This method involves calculating the expected buildup of pressure in the Mt. Simon Formation, based on the measured properties of the Formation and the records of the amounts of injection, and comparing the calculated pressures to the actual measured buildup of pressure. A smaller than expected buildup indicates that some leakage into the confining beds has taken place. The method is dependent on having accurate values for the hydraulic properties of the injection zone, quantities of fluid injected, and formation pressures. Although some of these factors are not known with certainty, URM has calculated rates of upward leakage based on a range of values that have been used in a previous simulation of this disposal reservoir. The calculations are described in Section 6.4.1.

It is possible that reaction of the waste with dolomite may cause any existing porosity of the dolomite to become plugged and limit upward flow. Calcium released from dissolving dolomite may combine with sulfate in the waste and produces gypsum. Precipitation of gypsum in intergranular or fissure porosity could reduce the permeability due to these features to very low levels.

## 6.4 Reservoir Hydraulics

The underground space into which fluids are injected is already filled with fluid. Disposal space is created by injection under sufficient pressure to displace the native fluid. Displacement results in transfer of the applied pressure from the injected fluid to the native rock and fluid. The pressure increase causes a slight dilation of the pore space and slight compression of the native and injected fluid, thereby creating space for the non-native fluid. The amount of excess pressure required and the direction and distance to which elevated pressures will extend depends on the properties of the formation and the fluids, the rate at which fluid is injected, the condition of the well, and the length of time that injection continues. Ideally, the permeability of the disposal zone greatly exceeds that of the underlying and overlying confining beds, and the result is horizontal, radial movement of fluid.

Good practice requires that the increase in fluid pressure in the disposal formation be temporary. When injection is stopped at the end of the life of the project, the fluids will continue to move from the area of high head at the well to the surrounding area where head is lower until the heads are redistributed and decline to an equilibrium near their original values. The return to original conditions will be more rapid if the total volume of interconnected porosity is large, the permeability is large, and/or the total amount of injected fluid is small.

Besides the desired horizontal movement of injected fluids due to injection, the increase of head in the disposal zone also tends to cause vertical migration through the confining beds. Safe disposal by deep wells requires that flow through the beds that protect overlying water resources will be very slow due to the very low permeability of the confining medium. The useful life of an injection system is ordinarily much shorter than the travel time across the confining beds, so the driving force below these beds is dissipated before significant vertical movement can occur.

In the following sections, the distribution of pressure increases that are expected to occur in the Mt. Simon Formation have been estimated. Also, the extent of waste and brine invasion of the Mt. Simon and Shady Dolomite has been estimated. Finally, natural regional flow in the Mt. Simon Formation is estimated.

6.4.1 Extent of Pressure Increases: Injection of fluid into the Mt. Simon Formation will cause the hydraulic head of the fluids in the formation to increase in the area surrounding the array of disposal wells at the CWM site. The area affected by the increases in pressure and head will be much larger than the area actually invaded by waste. It should be recognized that because of this difference in size between the pressure "front" and the waste "front", any material that migrates upward into the confining beds will be waste liquids in a relatively small area surrounding the well and natural brine in a much larger area.

The hydraulic properties of the Mt. Simon Formation determine the amount and extent of pressure increases that are expected to occur as a result of injection over an extended period. These properties include the flow capacity and storativity. As mentioned previously, the flow capacity has not been measured with a formal well test of a recompleted well, but analysis of the available data derived from pressure trends of unreconstructed and reconstructed wells and laboratory tests of core plugs suggest that the true value probably lies between 2,500 md-ft. and 3,500 md-ft. A value of 3,000 md-ft was used in the calculations described below. The storativity of the formation, defined as the amount of fluid taken into storage by a column of reservoir of unit cross sectional area per unit of head increase, has not been measured since the two-well interference test run in September, 1983 was inconclusive due to leaks in the wells. However, a value of storativity can be estimated from its component quantities, the thickness and porosity of the formation, and the compressibility of the rock and fluid. The effective thickness of the formation is estimated to be approximately 80 feet. The porosity of the more permeable zones, according to laboratory tests, is approximately 15%. The compressibility used in the calculations is $7 \times 10^{-6}$ $psi^{-1}$, which is a typical value for well cemented sandstones filled with brine of approximately 100,000 mg/L TDS. The fluid viscosity was assumed to be 1.0 centipoise, which respresents brine at 90° F with a salinity of 120,000 mg/L TDS.

Pressure buildups and declines were calculated using the non-equilibrium formula that describes the change in head in the vicinity of a well flowing at a constant rate which fully penetrates a confined aquifer of large areal extent (Theis, 1935). A computer program was used to calculate the pressure changes at a number of observation points due to injection into a multiple well system. The program employs the following version of the Theis solution ("exponential integral solution").

$$\Delta p = \frac{Q\,\mu\,(CF1)}{4\pi kh}\ W(x)$$

where: $\Delta p$ = change in bottom-hole pressure

$$x = \frac{\emptyset\ C_t\ r^2\ (CF2)}{4\ t\ k}$$

and: $\emptyset$ = porosity (fraction)

$\mu$ = viscosity (centipoise)

$C_t$ = total compressibility ($psi^{-1}$)

r = distance from well (ft.)

t = time (days)

k = permeability (md)

CF1, CF2 = units conversion factors

h = formation thickness (ft.)

Q = flow rate (gpm)

$$W(x) = \int_x^{\infty} \frac{e^{-x}}{x}\,dx$$

The pressure change at any observation point caused by injection into multiple wells is obtained by summing the pressure changes due to each individual well. A computer program was used to calculate the pressures that should exist in the Mt. Simon Formation due to injection into an array of six wells, if each well were to operate continuously at 30 gallons per minute.

The calculations indicate that the pressure buildup in a continuously operating 180 gpm well field would be substantial. Figure 30 is a profile of the water levels in the Mt. Simon Sandstone after 90

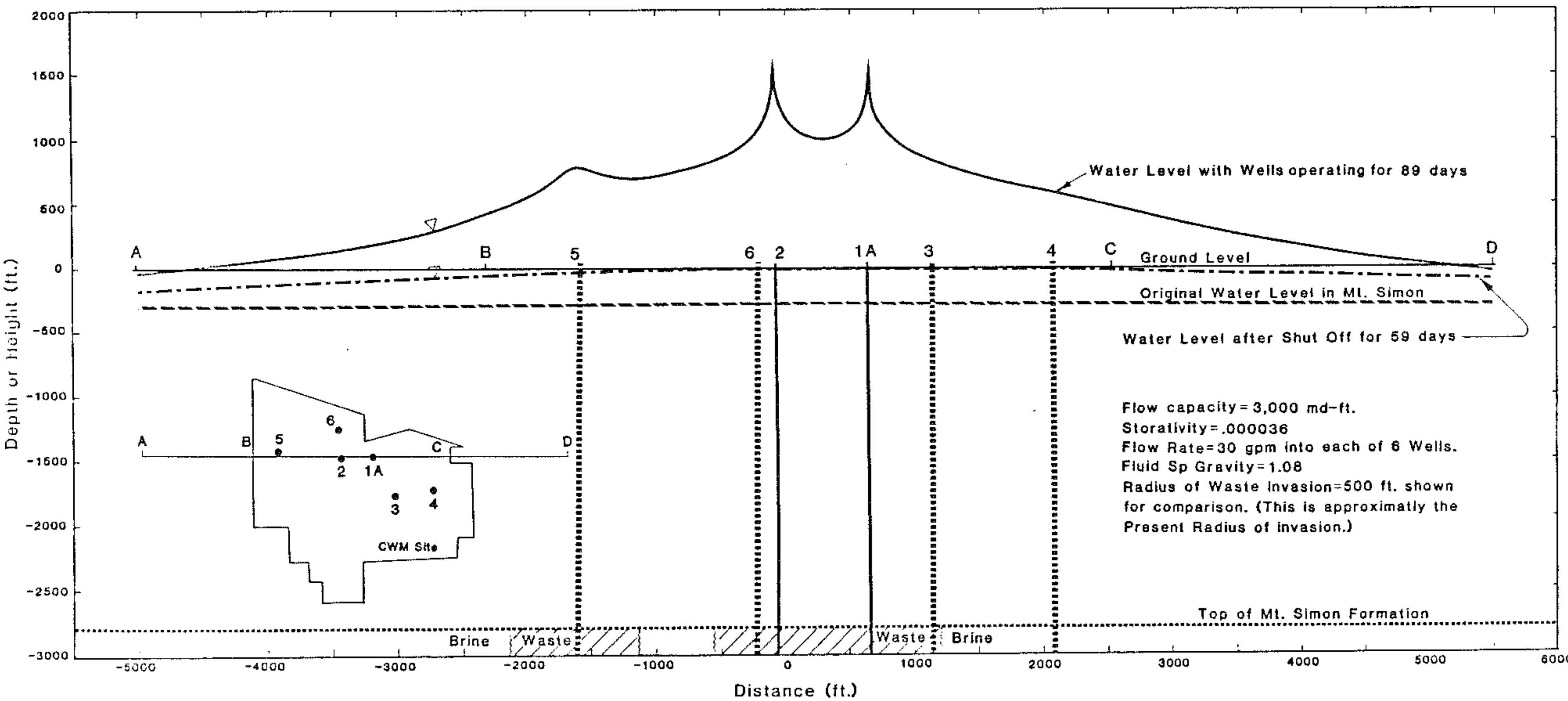





**Figure 30. Profile of Theoretical Water Levels in the Mt. Simon Sandstone**

days of injection. At this time, wellhead pressures would reach 750 to 800 psi. Figure 31 shows that after 90 days of injection Mt. Simon water levels would be above ground level within an area whose diameter is approximately 10,000 feet. A three-dimensional view of the distribution of pressure increases is shown in Figure 32. However, if the wells are then shut off, the water levels would fall below ground level within 60 days. The original water level in the Mt. Simon was approximately 300 feet below ground level.

Such increases would present a hazard to drillers in this area who were unaware of the pressure buildup. A procedure should be adopted by the Division of Oil and Gas whereby operators could be notified of this condition if they intend to drill in this area.

It is possible that calculations by previous CWM consultants (GSS, 1983) that indicated the Mt. simon Formation would be able to accept a continous 180 gpm at this site for 20 years were too optimistic. It is also possible that the formation properties employed in the above reservoir calculations are too pessimistic. As mentioned previously, the formation properties have not yet been formally measured, although analysis of wellhead pressure trends and core data suggest that the flow capacity is approximately 3,000 md-ft. It is possible that this value may be in error by as much as an estimated factor of two, based on the results of the drill-stem test conducted in Well No. 1. If some upward migration into the Shady Dolomite occurs, it may be possible to inject 180 pgm for 20 years even if the formation properties of the Mt. Simon estimated in this report are correct.

Another way to estimate the hydraulic properties of the Mt. Simon Formation is to mathematically simulate past injection. Using assumed formation properties and records of past injection volumes, an expected

**Distance (ft.)**

| Distance (ft.) | -5000 | -4263 | -3526 | -2789 | -2053 | -1316 | -579 | 158 | 895 | 1632 | 2368 | 3105 | 3842 | 4579 | 5316 | 6053 | 6789 | 7526 | 8263 | 9000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6263 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5526 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4789 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4053 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 9 | 41 | 64 | 75 | 73 | 58 | 32 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3316 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 77 | 123 | 157 | 174 | 170 | 146 | 109 | 64 | 17 | 0 | 0 | 0 | 0 |
| 2579 | 0 | 0 | 0 | 0 | 0 | 23 | 88 | 157 | 223 | 276 | 303 | 294 | 256 | 200 | 138 | 74 | 15 | 0 | 0 | 0 |
| 1842 | 0 | 0 | 0 | 0 | 0 | 66 | 150 | 246 | 344 | 431 | 478 | 457 | 391 | 307 | 219 | 125 | 59 | 0 | 0 | 0 |
| 1105 | 0 | 0 | 0 | 0 | 19 | 102 | 207 | 339 | 494 | 626 | 751 | 670 | 551 | 424 | 303 | 193 | 99 | 22 | 0 | 0 |
| 368 | 0 | 0 | 0 | 0 | 32 | 122 | 243 | 417 | 671 | 777 | 1094 | 926 | 720 | 546 | 355 | 244 | 131 | 42 | 0 | 0 |
| -368 | 0 | 0 | 0 | 0 | 31 | 121 | 239 | 405 | 613 | 732 | 915 | 964 | 839 | 681 | 450 | 272 | 145 | 50 | 0 | 0 |
| -1105 | 0 | 0 | 0 | 0 | 18 | 99 | 200 | 323 | 454 | 571 | 679 | 776 | 822 | 702 | 438 | 261 | 137 | 45 | 0 | 0 |
| -1842 | 0 | 0 | 0 | 0 | 0 | 63 | 145 | 234 | 330 | 419 | 492 | 544 | 542 | 462 | 335 | 210 | 107 | 25 | 0 | 0 |
| -2579 | 0 | 0 | 0 | 0 | 0 | 22 | 86 | 155 | 223 | 285 | 334 | 360 | 351 | 302 | 226 | 141 | 63 | 0 | 0 | 0 |
| -3316 | 0 | 0 | 0 | 0 | 0 | 0 | 29 | 81 | 131 | 175 | 207 | 221 | 212 | 180 | 131 | 72 | 15 | 0 | 0 | 0 |
| -4053 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 16 | 52 | 93 | 165 | 113 | 106 | 84 | 51 | 10 | 0 | 0 | 0 | 0 |
| -4789 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 9 | 23 | 29 | 23 | 8 | 0 | 0 | 0 | 0 | 0 | 0 |
| -5526 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| -6263 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| -7000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Figure 31. Grid showing theoretical height, in feet, of Mt. Simon water level above ground surface due to injection of 30 gpm into each of six wells for 90 days.
Flow Capacity=3.000 md-ft
Storativity=0.000036
Specific Gravity 1.08
Property line shown.

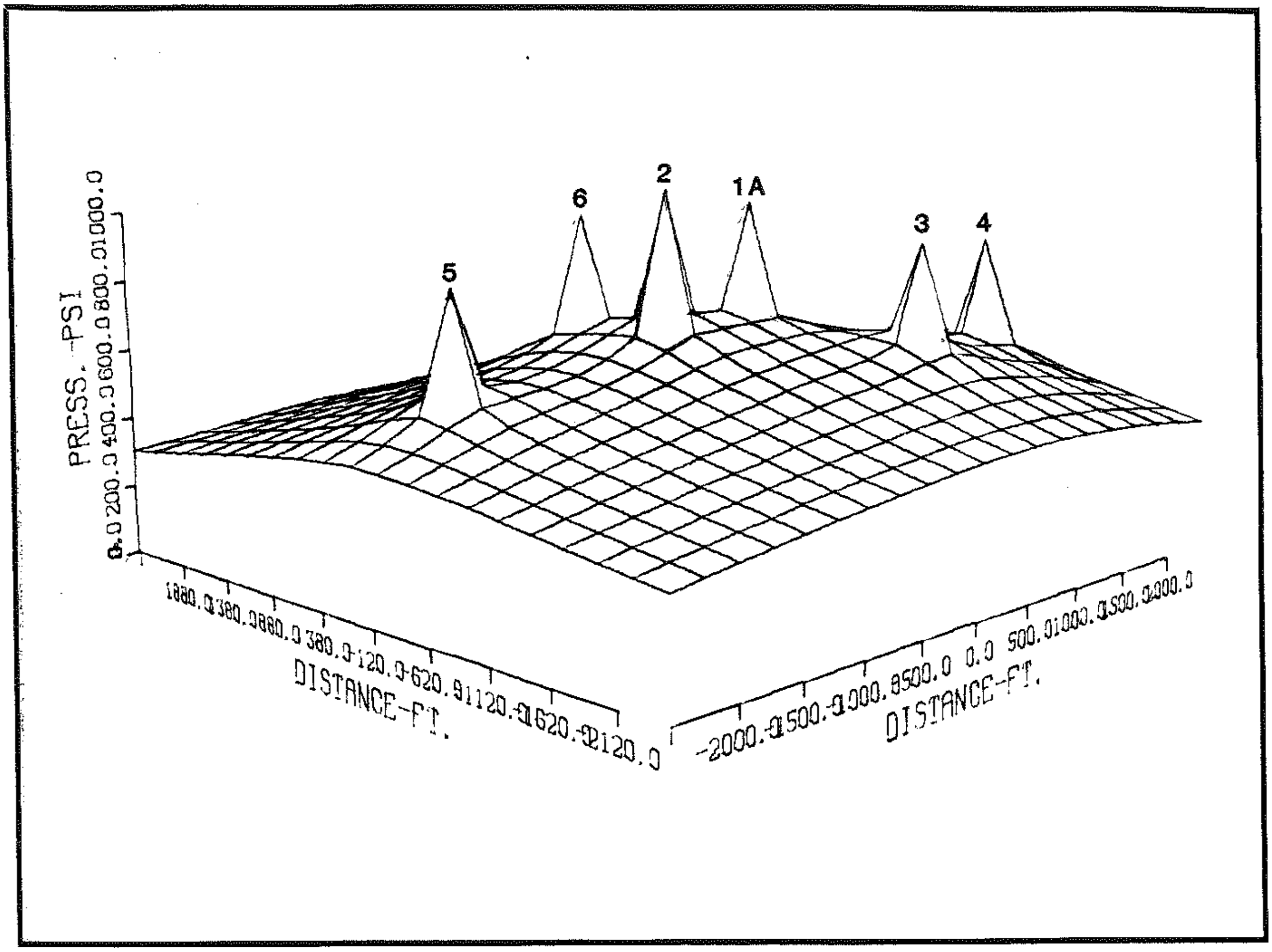



Figure 32. Pressure Distribution Around Six-Well Field, Each Well Injecting 30 gpm for 240 Days. Assumed Transmissivity = 3,000 md-ft. Assumed Storativity = 0.000036.

pressure buildup in the Mt. Simon can be calculated, based on the assumption of no upward leakage, and then compared to measured pressures. The assumed hydraulic properties can be changed until, by trial and error, the calculated pressures match the actual pressures. If the flow capacity and storativity required to obtain a match are significantly higher than the properties measured in well tests, it is probable that some upward leakage is occurring. It should be noted that upward leakage into the Shady Dolomite is unlikely to ever reach fresh ground water due to the presence of multiple deep permeable strata (Rome and Maynardsville Sandstones) that are capable of dispersing fluid horizontally beneath the thick Reedsville/Black River interval.

A mathematical simulation of waste injection at the CWM site was performed by a graduate student at the Ohio University at Athens (Nealon, 1982) as part of a master's thesis on disposal wells in Ohio. The simulation used records of volumes of injected waste and pressures through February 1980 obtained from state agencies. Three simulations were made, and the following hydraulic parameters were employed:

| Simulation | Mt. Simon Flow Capacity gal/day-ft. (md-ft.) | Mt. Simon Storativity (dimensionless) | Shady Dolomite Permeability gal/day-ft.$^2$ (md) |
|---|---|---|---|
| 1 | 70 ( 3,700) | .00013 | 0 (0) |
| 2 | 70 ( 3,700) | .00013 | $4x10^{-6}$ (.0002) |
| 3 | 70 ( 3,700) | .00008 | $4x10^{-5}$ (.002) |

(The exact relationship between gal/day-ft. and md-ft. depends on fluid viscosity).

The values of flow capacity used in this simulation were generally based on the reports of the analyses of core plugs that were submitted to the state. The value of 70 gpd/ft. was reportedly used in the final simulations since it produced the best head match in Simulation No. 1. The values of storativity in Simulations 1 and 2 were based on an estimation procedure (Lohman, 1972) in which formation thickness is multiplied by $1x10^{-6}$ $psi^{-1}$. The storativity was decreased for Simulation 3 to account for possible post depositional reductions in porosity. (It should be noted that these values of storativity and flow capacity are somewhat higher than those employed by URM in the simulations just described.) The value of permeability of the confining bed, which is the Shady Dolomite at the CWM site, was based on measured permeability of the Eau Claire Formation in Butler County at the Armco Disposal site, and thus represents only an approximate "starting point" for the type of calculations attempted in the study.

The simulations in this thesis were calculated using the Prickett-Lonquist finite difference computer model. The model was used to calculate the heads at flowing wells. A specific gravity of 1.089 was used to convert pressures to heads.

The simulated head in both the first and second simulations were the same, despite the fact that upward leakage was allowed in the second simulation. This indicates that the amount of leakage was relatively small and had virtually no effect on the buildup of head in the disposal reservoir. The rate of leakage was calculated to be 1,570 gallons per day.

When the storativity was reduced in the third simulation, the simulated heads were higher than the actual heads, despite the fact that the permeability of the confining bed was increased by one order of magnitude. An allowance for an even greater rate of leakage would have been required to reduce the simulated heads to the level of the measured heads, using the reduced storativity. Additional leakage could have been obtained in the model by further increasing the permeability of the confining beds. The rate of leakage in the third simulation was reported to be 22,000 gallons per day.

It is believed that the flow capacity and storativity of the Mt. Simon Sandstone used in Simulation 3 of this thesis represent the modeled values that were closest to the actual values. As mentioned previously, the actual values have not been formally measured, but have been inferred from core data and by analysis of pressure falloff trends described in the preceding pages and illustrated in Appendix B. The inferred values for flow capacity and storativity are 3,000 md-ft. and .000036, respectively. It is believed that the thesis model is not strictly valid because flowing pressures and not shut-in pressures were simulated. This was done because only flowing pressures were available to the author of the thesis. Use of shut-in pressures would have eliminated a major source of uncertainty, which is the amount of plugging or dissolution (positive and negative skin effects, respectively) that may or may not have been present at the sand face of each well.

The model is useful in that it illustrates the possible magnitude of upward leakage, if the author's assumptions about the hydraulic properties of the Shady Dolomite and the Mt. Simon Sandstone were correct. The third simulation resulted in leakage of 22,000 gallons per day. This is the total volume of leakage, including both waste liquid and native brine. In order to put the leakage in the proper perspective, it is advantageous to recalculate leakage in terms of the distance of upward penetration of the confining beds, assuming that leakage occurs through intergranular porosity and not through fractures.

The rate of upward flow (rather than the daily volume of upward flow) can be estimated using a form of Darcy's law:

$$\bar{q} = \frac{k \Delta h}{\emptyset \Delta L}$$

where $\bar{q}$ = pore velocity (ft/day)

$k$ = permeability (ft/day)

$\Delta h$ = difference in hydraulic head across Shady Dolomite (ft)

$\Delta L$ = thickness of Shady Dolomite (ft)

$\emptyset$ = porosity (fraction)

It was assumed that the Rome and Mt. Simon Sandstones orginally had the same head level. It was assumed that the difference in hydraulic head across the 60-foot thick Shady Dolomite during operation is an average 1,300 feet in the area near each well where, according to estimates presented later, the Mt. Simon Formation contains waste. The increase was based on operation of six wells at 30 gpm each for 90 days. The permeability was that used in the third simulation (Nealon, 1982) $4 \times 10^{-5}$ gpd/ft$^2$ (= $5.4 \times 10^{-6}$ ft/day). The rate of upward leakage was calculated to be 0.84 feet per year, assuming a porosity of 5%. If a porosity of 1% is used, the rate of upward leakage would be calculated to be 4.2 feet per year. Therefore, in 20 years, the distance of penetration of the Shady Dolomite confining beds is theoretically only about 17 feet ($\emptyset$ = .05) or 85 feet ($\emptyset$ = .01).

The distances of penetration of natural Mt. Simon brine into the Shady Dolomite outside the area containing wastewater are, of course, less than this value, since the pressure buildup decreases with distance from the wells. The total simulated leakage volume of 22,000 gallons per day (waste plus brine) can therefore be accomodated by an upward penetration of waste of slightly more than one-eighth of one inch per day near the well and lesser amounts for brine in the area surrounding the site. Of course, if the lower value of permeability that was employed in the first two simulations is used in this calculation, the calculated penetration rates are only one-tenth of those mentioned above.

The above discussion is for upward migration through intergranular porosity, as opposed to fracture porosity. As discussed earlier, there is evidence that microfractures exist in the Shady Dolomite. The micro-fractures appear to be closed in some areas, due to plugging by dolomite crystals, but porosity remains in other areas. An irregular network of partially-filled microfractures may be a more accurate representation of the true nature of the kind of porosity of the Shady Dolomite that actually permits flow in the formation. These fractures may or may not become plugged upon contact with waste. They would not become plugged upon contact with brine.

6.4.2 Fluid Invasion: Injected waste should occupy a relatively small area around each well at the CWM site. The minimum size of this area can be estimated by making simplifying assumptions. It is assumed that the waste will occupy a cylinder centered at each well. The height of the cylinder is the effective thickness of the Mt. Simon Formation and the volume of the cylinder is the volume of porous rock that could contain the volume injected. The radius of this cylinder is:

$$r = \sqrt{\frac{v}{\pi h \emptyset}}$$

Where v = total volume of injected waste
h = effective thickness of formation (80 feet)
Ø = effective porosity (0.15)

The estimated current volumes of waste injected into the Mt. Simon Formation and the corresponding theoretical radii of invasion are shown below:

| Well | Volume Injected (Millions of Gallons) | Radius (Ft.) |
|---|---|---|
| 1 | 38 | 370 |
| 1A | 87 | 560 |
| 2 | 61 | 470 |
| 3 | 78 | 530 |
| 4 | 87 | 560 |
| 5 | 32 | 340 |
| 6 | 8.7 | 180 |

The theoretical radius to the waste front of a well that operates continuously for 20 years at 30 gpm would be 1,058 feet.

The actual shapes and sizes of the waste-invaded areas will be different from the theoretical minimum circular areas for two reasons. First, the shapes will be distorted due to interference of the wells with each other. Liquids injected into groups of wells tend to migrate away from the center of the well field, as shown in Figure 33. The figure is only an approximation, since it was simulated with all wells operating continuously and simultaneously. In reality, some of the wells were inactive at various times, and flow rates changed from month to month, whereas the figure shows the theoretical front positions assuming all of the quantities of liquid listed above were injected at the same time. However, the figure shows the effect of multi-well operation on the approximate shapes of waste fronts.

The second reason that the shapes of the areas will not be exactly as shown is that the Mt. Simon Sandstone is not homogeneous. The formation is composed of layers of different thickness, each of which has a different permeability and porosity. Waste will tend to travel farther

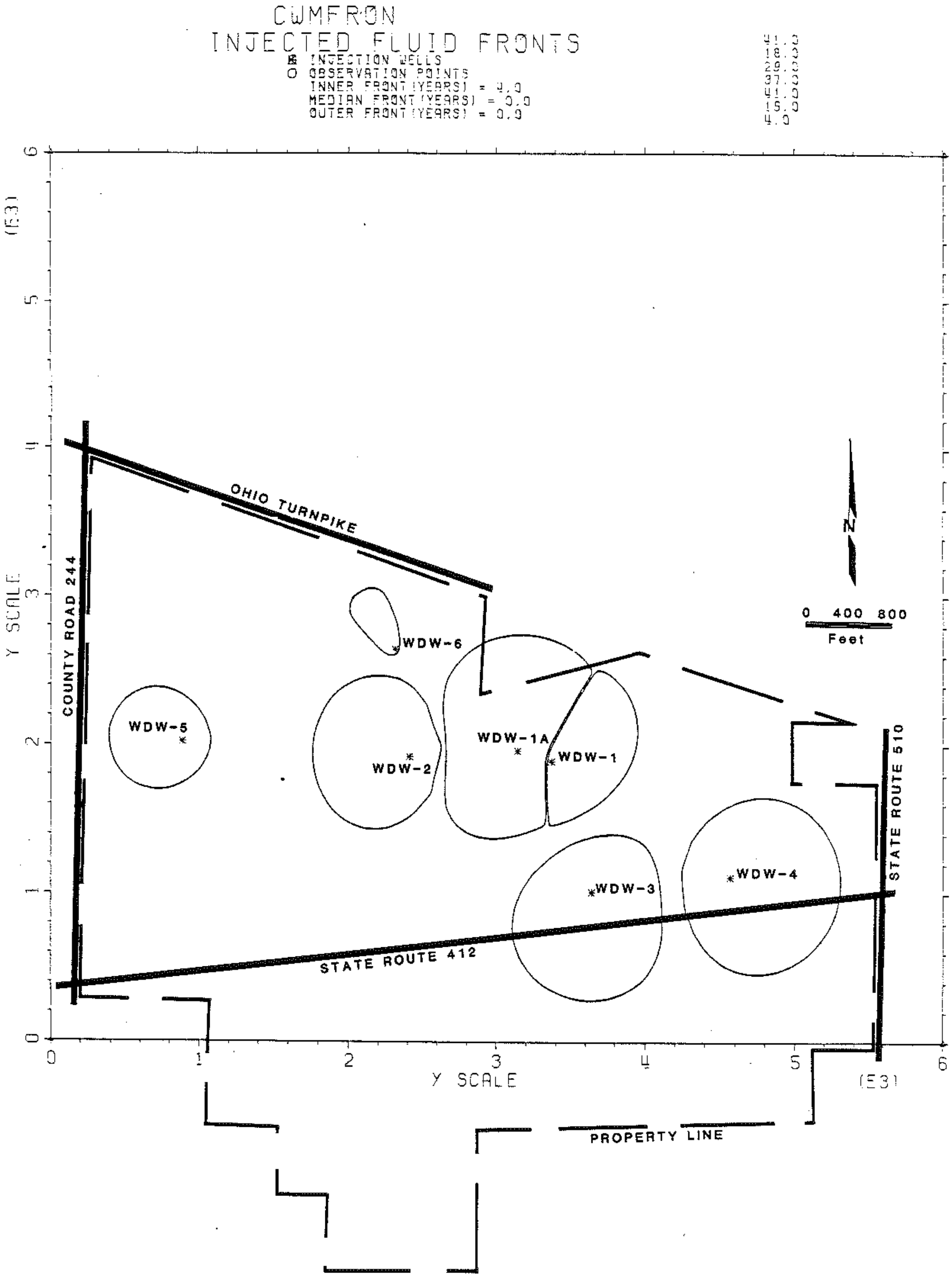



**Figure 33.** **Theoretical Waste Fronts at Chemical Waste Management assuming all wells had operated simultaneously.**

in the layers having higher permeability. In addition, the leading edge of waste in each individual layer will not form a sharp transition between areas completely filled with either waste or native brine. Instead, the contact between the two fluids will be a zone of mixing due to dispersion and diffusion of the waste front. These effects result in some of the waste traveling farther, in the same amount of time, than the theoretical values listed above. Within this diffuse transitional area between areas completely filled with waste and completely filled with native brine, the concentration of waste decreases with increasing distance from an injection well. The true distribution of waste concentrations is not easily predictable because the dispersivity of the formation is not easily measurable. Laboratory tests of core materials typically underestimate dispersivity because this property is dependent on the degree of nonhomogeneity of the formation at both microscopic and macroscopic scales. In other words, dispersivity depends not only on size, roughness, and sorting of the individual sand grains, but also on larger features of bedding such as the arrangement and size of interbeds of different grain size, degree of cementation, and clay content. For these reasons, small concentrations of waste may be found at distances perhaps twice as far from the wells as those listed above.

Since the specific gravity of the waste (1.07-1.09) is approximately the same as the native brine in the Mt. Simon Formation, the effects of density differences between the fluids are expected to be small. The waste should tend neither to rise to the top or to sink to the bottom of the disposal zone. Another factor which prevents density segregation is the layered nature of the formation, since layers with low permeability would tend to retard vertical movement of water between layers with higher permeability.

6.4.3 Regional Subsurface Migration: A prime objective of subsurface disposal is to ensure that contaminants are safely removed from the biosphere. Safe operating practices, good well design, and appropriate geological conditions are necessary to ensure that wastes are injected into the disposal formation and are contained there until the pressures needed to achieve injection have dissipated and declined to near their original values. Once this has been achieved, the slug of injected material will begin to migrate according to the natural, regional flow of water in the formation. For continued, long-term safety of projects that utilize disposal by deep wells, the disposal site should be located so that wastewater will not rapidly migrate to a regional ground-water discharge area and flow to the land surface or into an underground source of drinking water.

Deep well disposal is practical because the rate of subsurface flow in many deep, porous, brine-bearing geologic formations is extremely slow. In addition, wastewater moving in such formations will undergo a number of changes in composition. These changes are the result of dilution and dispersion of the waste stream, as well as more fundamental chemical changes caused by complex interactions with the minerals in the reservoir rock and confining beds, and with the native formation water. The primary consideration that should be used in an evaluation of the ultimate fate of the waste, however, is the rate of subsurface migration.

A number of recent studies of deep saline aquifers have suggested that the brines contained in most of these formations are in motion, although at a very low rate in many cases, rather than being completely stagnant as previously thought by some researchers. Some of the regions that have been studied are the Western Canada Sedimentary Basin (Hitchon, 1969a, b; Toth, 1978), the San Juan Basin (Berry, 1958), the Permian Basin (McNeal, 1965), the Paradox Basin (Hanshaw and Hill, 1969) the Austrialian Surat Basin (Hitchon and Hayes, 1971), the Illinois Basin (Bond, 1972), and the Palo Duro Basin (Bassett and Bentley, 1983). These studies have showed that commonly, differences in hydraulic potential exist in different parts of the formation(s) under study. Differences in hydraulic potential indicate the possibility for water movement, if permeable media are present. In many cases, the rates of ground-water flow in deep saline aquifers were calculated using Darcy's law and found to be generally less than the rates in shallow, fresh-water aquifers. The general picture of regional flow systems that has emerged from these studies suggests that deeper beds have less porosity and permeability, they contain water that is more mineralized, and they have generally more sluggish circulation compared to the shallower formations used as sources of drinking water.

The patterns of flow in sedimentary basins are generally complex, and are influenced not only by the topography of a region, but also by the arrangement of beds of low and high permeability. The topography of the earth's surface provides the driving force for most subsurface flow, because the water table generally follows topography. Sedimentary layering modifies the general pattern of flow from high areas to low areas by channeling flow preferentially along beds of higher permeability. A significant flow of water from one of these beds to another may occur where intervening low-permeability beds are thin, absent, or faulted. In general, flow across intact low-permeability beds would be expected to be at rates much lower than those in beds of higher permeability. Passage of large volumes is possible, however, if cross-formational flow takes place over large areas.

The rate of natural movement of brine in the Mt. Simon Formation has been calculated in two previous studies in Ohio (Clifford, 1973, 1975; Nealon, 1982). Clifford (1973, 1975) studies the broad topic of subsurface injection in Ohio, with emphasis primarily on the Mt. Simon Sandstone. In this study, data on the original, preinjection pressures in the Mt. Simon Sandstone were obtained from records of injection wells in Ohio. The pressure data were in the form of drill-stem test results and static water level measurements. The pressures were converted to hydraulic heads using the variable density correction method outlined by Bond (1972). Use of fresh-water density to convert pressures to water levels tends to exaggerate the height of the effective head differences in formations where salinity, and therefore density, is variable. The resulting hydraulic gradients were less than 7 feet per mile, and averaged approximately 4 feet per mile. Rates of flow in the Mt. Simon can be calculated using a form of Darcy's Law:

$$q = (.069)\ \frac{ki}{\emptyset}$$

where q = flow rate (ft./year)
k = hydraulic conductivity (ft./day)
i = hydraulic gradient (ft./mile)
$\emptyset$ = porosity (fraction)

The permeability of the Mt. Simon Formation has been measured by drill-stem tests and core analysis at several waste disposal sites in Ohio. The values of permeability range from 3.0 md to 75 md. The analogous values of hydraulic conductivity are approximately 0.0073 and 0.182 ft./day, respectively. An average value of 38 md (0.0925 ft./day) appears to best represent conditions at the CWM site. Using a value of porosity of 0.15, the following flow rates were calculated for different values permeability and hydraulic gradient.

| k (md) | i (ft./mile) | $\emptyset$ | q Ft./year | q inches/year |
|---|---|---|---|---|
| 38 | 4 | .15 | .17 | 2 |
| 38 | 7 | .15 | .3 | 3.6 |
| 75 | 4 | .15 | .33 | 4 |
| 75 | 7 | .15 | .59 | 7 |

The table suggests that the flow rates in the Mt. Simon Sandstone are extremely low.

The pressure data utilized by Clifford (1973) to estimate the hydraulic gradient were reviewed by Nealon (1982). Nealon recalculated the conversion from pressure to head level using the density of the Mt. Simon brine at each site, whereas Clifford had used Bond's method of estimating the average density difference in the formation between this well and adjusting the head in the deeper well accordingly. The result was a lowering of the calculated head levels at those sites where the Mt. Simon lies at great depth (greater than 4,000 feet) and contains very dense brines. As a result of utilizing different calculated flow rates, these two workers produced head maps indicating flow was in different directions. Nealon's map shows eastward flow down into the Appalachian Basin, whereas the lowest head on Clifford's map is at the CWM site, with the result that flow appears to move toward the CWM site from other parts of Ohio. Nealon's calculated rate of flow was 1.2 inch/year.

The calculated rate and direction of flow therefore depend on the method used to convert pressures to hydraulic potentials. The proper way to do this with a limited data base of pressures and fluid densities is currently a controversial subject. If the fluid density and the true fluid pressure were known at every point in the flow field, a proper map of hydraulic potentials could be constructed which would show true directions of flow in the formation. Bond (1972) has illustrated the difficulties in making such maps with limited data. Bond mapped the hydraulic potentials of the Mt. Simon Formation in Illinois and found that, like Ohio, the head differences were so small that use of different density correction techniques would reverse the directions of indicated flows.

It appears from the above studies that no strong hydraulic gradients are present in Ohio. The Great Lakes Area is one of generally low relief, and the lack of major differences in topography would tend to prevent generation of strong hydraulic gradients. It is probable that the head gradient is actually no greater than 7 feet per mile and may in fact be much less, with the result that flow in the Mt. Simon may be so slow that it is almost stagnant.

However, if the worst case is assumed, the calculated effects are still insignificant. Assuming that flow in the Mt. Simon Sandstone is northward from the CWM site at a rate of 7 inches per year, it would take 72,000 years for waste to reach the area of the south shore of Lake Erie. It would then take considerable time for water to move from the Mt. Simon across the confining beds into an underground source of drinking water or into the lake. Present indications, however, are that the hydraulic head in the Mt. Simon is lower than the head in fresh ground water or in the lake, so there is no apparent energy available to cause upward flow. Attempts to calculate cross-formational flow rates result in downward flow from Lake Erie into the Mt. Simon Formation.

Even if wastewater were to flow upward with the natural brines, it would be spread over a wide area and would experience radical chemical changes while passing through over 2,000 feet of shale and dolomite. Probable chemical reactions include neutralization and precipitation of many of the metal ions in the waste. Also, it should be remembered that if the ultimate natural discharge point of the Mt. Simon Formation is the Lake Erie/Lake Ontario/St. Lawrence drainage, discharge of natural brines is occurring today with no apparent detrimental effects. The weight of available evidence therefore suggests that the danger of emplaced waste rapidly migrating to discharge points in concentrations that could cause environmental impairment is extremely low. Possible cross-formational flow from the Mt. Simon into possible oil reserves in the Maynardsville Sandstone or the Knox Unconformity would be retarded by the low permeability of the intervening dolomite units and the lack of vertically directed head gradients that will exist once injection has ceased. It is therefore concluded that regional subsurface migration does not present a hazard to ground water or to the surface environment.

## SUMMARY

This report on waste injection at the CWM site in northern Ohio was organized to address two prinicipal areas of concern: construction and operation of the wells, and suitability of the geologic environment. Accordingly, the summary and conclusions presented below are organized into those categories.

### Construction and Operation of Injection Wells

- Integrity tests of six injection wells at the CWM site indicated that there were mechanical problems with each of the wells.
- Well No. 1A was found to have a hole in the fiberglass part of the long string casing in the depth interval from 2,591 to 2,606 feet. It is estimated that this leak may have started in late 1981 and an estimated 7 to 20 million gallons was injected into the Maynardsville Sandstone.
- Well No. 2 has not been in service since December, 1980. Testing at that time indicated a leak in the steel casing in the depth interval from 2,225 to 2,376 feet. A liner had been installed to cover a corroded area of the casing in the interval 1,903 to 2,364 in 1979. This liner was later found to be corroded in January, 1981. When the casing was pressurized in the Fall of 1983, the leak appeared to be only on the order of a few gallons per minute at 580 psi, with saturated brine as the test fluid. This leak may have partially scaled itself due to precipitation of calcium sulfate during the period that the well was idle. Although the amount of leakage is difficult to estimate, an estimated minimum of 1.5 to 4 million gallons of waste was injected into the Maynardsville Sandstone or the overlying Knox Unconformity.
- Well No. 3 was tested in Fall, 1983 and found to have a leak in the fiberglass part of the casing in the depth interval 2,389 to

2,626 feet. It is estimated that up to 12 million gallons of waste was injected into the Maynardsville Sandstone starting in October, 1982. Some of this waste may have flowed through a split in a box-end connection between sections of the fiberglass injection tubing at a depth of 1,300 feet, and then down the annulus to the leak. Although there was communication between tubing and annulus through the split, an inflatable packer that had been installed at the base of the tubing was still in place in late 1983.

- Well No. 4 was tested and found to be leaking in the interval 2,594 to 2,656 feet. There was another hole in the casing above 2,333 feet, but since the hole would not accept the test fluid until the casing pressure was raised to high levels, the hole was apparently opposite a low-permeability confining formation. It appears that no fluid entered the leak until the formation was parted using a test pressure in excess of operational pressures. It is estimated that up to approximately 15 million gallons was injected into the Maynardsville Formation since Summer, 1981 through the lower leak.
- Well No. 5 was tested and the casing interval from 2,406 to 2,768 feet accepted a very small flow of fluid. The upper part of the casing, above 2,406 ft., had a hole in it, which, like the upper leak in Well No. 4, would not accept fluid until a high test pressure was applied. The amount of leakage that may have occurred below 2,406 feet in Well No. 5 is not easily estimated, but it is considered to be relatively small.
- Well No. 6 was tested and found to have severe corrosion of the carbon steel long casing in the interval just above the basal Inconel Alloy section of the casing. The corroded interval was 2,682 to 2,728 feet. It is estimated that up to 50% or more of the flow into this well since Summer, 1982 entered the Rome Sandstone. The total leakage is estimated to have been approximately 9 million

gallons.

• The amounts of leakage listed above are not accurate measurements of the true values. They are estimates based on a review of the operating records and, in some wells, comparison of the flow rates into the leak with flow rates into the Mt. Simon at the same surface pressure during testing.

• The cause of the leaks that occurred in fiberglass casing is not known. Among the possibilities are damage by downhole tools during reworking or cleaning of the wells, or damage by explosives used in the open-hole section at the bottom of the wells to clean and/or stimulate the disposal zone. In several cases, a scraping tool was run in the fiberglass casing to remove excess cementing materials after casing repairs. Caliper logs made for some of these wells show that the inner surface of the fiberglass casing was rough and irregular.

• The casing corrosion evident in Wells No. 5 and 6 was probably caused by contact of waste with the casing. Unlike the other wells at the CWM site which have a basal 400-foot section of corrosion-resistant fiberglass, Wells 5 and 6 have a basal section of corrosion-resistant Inconel alloy casing that is only 60 feet long. Since considerable problems were experienced with the design of the bottom-hole packers, these wells were in effect operated like the other wells at the site, with the annular oil floating directly on waste under the packer in the bottom of the well. However, a 100-foot error in locating the base of the oil at the packer would have caused more problems in Wells No. 5 and 6 since only the lower 60 feet of casing was acid-resistant. It is possible that the severe corrosion in Well No. 6 was started or aided by waste migrating upward outside the end of the casing due to a poor cement job. The corrosive waste may have flowed upward into the Rome Sandstone, corroding the casing from the outside first. The corroded interval almost exactly matches the Rome Sandstone interval, which apparently absorbed all the upward-migrating fluid.

- Detection of leaks in injection wells which do not have bottom hole packers or sealing elements depends on information from the gauges that monitor the casing fluid pressure and the injection pressure. Any leaks which occur very near the bottom of the wells would be difficult to detect with the monitoring techniques used, due to the poor resolution of the surface pressure gauges, and variations in the density of the waste. In addition, friction losses while a well is in operation at 30 gpm would be on the order of 5 psi for a 2,800-foot well equipped with 3.5-inch diameter fiberglass tubing. Weekly fluctuations of 10 psi in the pressure differential were common, according to operating records. Since variations can be caused by factors other than casing leaks, it is not clear what criteria were used to determine the necessity for well inspections. Dissassembly of a well upon every occurrence of minor variations was not necessary. The wells were, however, subjected to integrity tests on a number of occasions in the past. Although records do not indicate the reasons for each inspection, it is probable that some of them were prompted by abnormalities in pressure differentials. In some cases, the records indicate that no leaks were found.

- The pressure differential at Well No. 3 in the period July, 1980 to January, 1981 was less than half of the value that would have been expected of a well with a packerless hydraulic seal. In early 1981, the well was equipped with an inflatable packer at the base of the tubing. It was intended that this well would operate with zero pressure at the casing head, since the packer should have isolated the fluid system in the casing from that in the injection tubing. During later 1981 and early 1981, however, the casing pressure steadily increased. By the fall of 1982, the casing pressure had more or less stabilized at approximately 480 psi, while the injection pressure, which had fallen steadily during the previous year, stabilized at approximately 400 psi. As soon as changes in the casing pressure began to track changes in the injection pressure, there was evidence that the two fluid systems were again in direct communication. At this point, in late 1982, it would have been appropriate to investigate the cause of the abnormally small pressure differential.

- The sudden 20 gpm increase in flow rate at Well No. 3 that occurred in late October or early November, 1982 was an abnormality that would ordinarily be cause for inspection of the well.
- The repeated addition of oil to casing fluid systems of several wells suggests that some type of abnormality was recognized.
- Company records of operating parameters include numerous notes of adjustments made to surface equipment, including monitoring systems, and the records appear to be relatively detailed and complete. Monthly reports made to the State of Ohio appear to have contained notices of all impending down hole inspections, but notices of surface adjustments such as the additions of oil to well casings are not complete. Pressure differentials and flow rates were not directly reported, but the information necessary to calculate monthly averages of these quantities, such as average pressures and daily injection volumes, appears to have been regularly and accurately reported. Interpretations of the significance of these data do not appear in records of CWM or of OEPA that were furnished to URM.
- The wells at the CWM site are scheduled for reconstruction. The new well design allows for independent pressurization of the casing (annulus) fluid and continuous monitoring of its volume by direct observation of the liquid level inside a reservoir connected to the casing. Using this system, any leakage such as that which

has occurred in the past should be detectable when manual observation is made of the level in the reservoir. This is typically done on an hourly basis. Sudden loss of all the fluid in the reservoir should be cause for taking the well out of service immediately. Slow loss of fluid over a period of hours should be cause for taking the well out of service if the trend continues for 24 hours, or if the reservoir becomes empty.

Site Suitability

- Wastewater is injected into an underground rock formation (approximately 85 to 140 feet thick) called the Mt. Simon Sandstone. The top of the formation occurs at a depth of approximately 2,800 feet. The formation is overlain by the Shady Dolomite, which is approximately 60 feet thick.
- The sequence of sedimentary rocks at the site consists of rocks ranging in age from Silurian to Cambrian. The bedrock surface is overlain by approximately 30 to 60 feet of unconsolidated glacial deposits.
- Fresh ground water is present in the basal glacial deposits and in the Silurian "Big Lime" rocks. Some of this water is of marginal quality due to the presence of high concentrations of sulfate. The deepest water well at the site extends to a depth of 200 feet. Untapped supplies of fresh water may exist at deeper levels in the "Big Lime", which is present down to a depth of approximately 600 feet. The disposal wells at CWM have double casings down to a depth of 600 feet.
- The Big Lime is underlain by approximately 1,000 feet of Ordovician Shale and limestone. Records of boreholes that were drilled with cable-tool machines in eastern Sandusky County indicate that no inflows of brine were encountered while drilling below the base of the "Big Lime" until the Knox Unconformity (top of Cop-

per Ridge Dolomite) was penetrated at a depth of 2,000 to 2,500 feet, depending on location. Although this does not mean that the "dry" interval has zero permeability, it does suggest that the permeability of these beds is relatively low, and that no permeable faults, fissures, or layers of high permeability were intersected in this stratigraphic interval by the five nearby exploratory boreholes of record.

• Oil is present in the Trenton Formation at a depth of approximately 1,300 feet in west-central Sandusky County. Most exploratory activity in this oil field was conducted in the early 1900's. The chance that some of these holes were drilled to the top of the Mt. Simon Formation is considered to be very low. It would have been difficult to drill below the Knox Unconformity (depth approximately 2,000 feet) due to the inflow of water at this depth. Setting casing to this depth would have involved considerable expense and better equipment. Records of deep wells that were drilled to the Mt. Simon in the 1960's within the area where significant increase of pressure are expected to occur due to injection indicate that all of the wells have been plugged.

• There have been some shows of oil or gas reported in the Maynardsville Sandstone in Sandusky County. The closest reported show was for gas, in Townsend Township, approximately 3.8 miles southeast of the site.

• The general geological structure in this area is one of gently eastward dips of the stratigraphic units. No faults have been mapped in eastern Sandusky County.

• After several years of operation of the disposal wells at this site, no seismic activity has been reported in eastern Sandusky County. The area appears to be one of low seismic risk. An array of seismic detectors near Anna, Ohio, operated for the Nuclear Regulatory Commission by the University of Michigan, is capable of detecting tremors in Sandusky County of magnitude 2.0 or greater.

• The Mt. Simon Formation is a tan to reddish, very fine to coarse grained, poorly to well cemented sandstone that contains thin silty and shaly beds. The sandstone is cemented with both siliceous and carbonate natural cements.

• Core tests, drill-stem tests, and pressure falloff trends of shut-in wells indicate that the flow capacity of the Mt. Simon Formation may be approximately 3,000 millidarcy-feet (55 gallons per day per square foot). However, a formal, definitive well test has not been conducted, and this value may be somewhat in error. The maximum error is estimated to be a factor of two, based on drill-stem tests of thicker intervals that included the Mt. Simon.

• The natural formation brine in the Mt. Simon Formation contains over 120,000 mg/L total dissolved solids. The high concentration of calcium in the brine and the high concentration of sulfate in the wastewater causes precipitation of gypsum from mixtures of the two waters. For this reason, a fresh-water buffer has preceded injection of waste in each of the disposal wells.

• The pressure necessary to hydraulically fracture the Shady Dolomite or the Mt. Simon Formation is not accurately known. Service company records indicate that most of the CWM wells have been fractured during acid stimulation jobs, but the pressure at which this occurred was not measured and/or recorded. A disposal well should not be operated at a pressure higher than that which would cause fractures to be created, grow, or extend in the reservoir beds or the confining beds. The original operating pressure limit of 840 psi surface pressure was based on a waste specific gravity of 1.04. Recalculating the limit with the more accurate specific gravity of 1.07 to 1.08 results in a limit of approximately 790 psi. This limit should be observed until the in situ stress at the site is measured.

- Microscopic examination of samples of the Shady Dolomite revealed microfractures that were partially filled with dolomite. Laboratory tests of core plugs of Shady dolomite resulted in permeabilities of less than 0.01 millidarcies. It is not known whether these core plugs contained microfractures, or what effect the microfractures have on the bulk permeability of the Shady Dolomite.
- Injection of waste into the Mt. Simon Formation at the CWM site has been simulated by a graduate student at Ohio University using a finite-difference computer model. The pressure-matching technique that was employed is subject to errors caused by the use of flowing rather than shut-in pressures. Flowing pressures may be affected by "skin" effects caused by partial plugging of the well at the formation face. The computer simulation using values of hydraulic properties that are considered to be the most reasonable resulted in an estimated upward migration into the first confining bed (Shady Dolomite) of between 0.84 ft./year and 4.2 ft./ year, for assumed porosities of 5% and 1%, respectively, in the area immediately adjacent to each well where the waste is present.
- Due to uncertainties in the data available to make such simulations as the one just described, it is not known whether the calculated amounts of upward flow out of the Mt. Simon Sandstone are too low, too high, or approximately correct. It is possible that the amount of upward flow of waste is lower than that described above due to possible reactions of the waste with the dolomite confining rock. Liberation of calcium from the dolomite by the acidic waste could result in precipitation of gypsum due to the high concentration of sulfate in the waste. Gypsum could have a plugging effect on the available intergranular or microfissure porosity visible in microscopic examination of the Shady Dolomite. Thus, any upward flow that occurs may consist almost wholly of natural

brine. It would not be possible to determine the relative amounts of brine leakage versus waste leakage using simulations or well tests, since only a very small part of the upward flow would involve wastewater. In any event, upward flow is of more academic interest than environmental concern since upward-migrating liquids could move no higher than the Rome Sandstone before their excess hydraulic head was dissipated. Much of any upward-migrating waste would remain trapped in the Shady Dolomite.

- The future increases of pressure and head expected to occur in the Mt. Simon Sandstone were calculated by nonleaky aquifer methods for an array of 6 wells operating at 30 gpm. It was found that wellbore pressure increased to near the fracturing point in less than one year. Calculations of total injectivity at this site made by previous CWM consultants may be too optimistic. However, slight leakage into the Shady Dolomite may increase overall injectivity by reducing the rate of pressure buildup. Also, increases of well efficiency due to acid dissolution or fracturing of adjacent rock would also tend to increase injectivity by lowering wellhead pressures.
- The theoretical distance of invasion of wastewater around each well today averages approximately 500 feet. The radial distance of invasion for a well operating continously at 30 gpm for 20 years is approximately 1,050 feet. The actual distances of penetration of mixtures of waste and brine will be somethat greater due to dispersion and to preferential migration along beds of higher permeability.
- The increases in pressure in the Mt. Simon Formation will be temporary since the regional continuity of the formation gives it the capacity to absorb the relatively small volume of wastewater in a reservoir of considerable size. If six wells are operated at 30 gpm continously for 6 months and then turned off, within 3 months

the water levels would be below the land surface at the CWM site. Regardless of the duration of injection, the pressures will ultimately return to near their original levels. The pinch-out of the Mt. Simon in southwestern Ontario is too distant to have an effect on the rates of pressure buildup and decline caused by injection at the CWM site.

- The rate of natural regional migration for Mt. Simon brines has been calculated in several studies to be on the order of less than one foot per year. Migration of the slug(s) of waste a distance of one mile would take thousands of years. The pressures will again be at normal levels during this migration. In the long term, conditions would be the same as they are today, where Mt. Simon brines do not have sufficient hydraulic potential to enable them to seep upward into sources of drinking water.

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Appendix A

# APPENDIX A

Daily Activity Log

## APPENDIX A

URM, Inc.
Daily Activity Log
Vickery Site Inspections

All field operations were supervised by TWO, Inc., a CWM consultant. A representative from URM, Inc., was present to observe or collect data and to serve as a consultant to the OEPA during the procedures listed below.

9/19/83 - Rig up pump truck to Well No. 6. Pump 3,000 gallons 9.9 lb/gal. NaCl brine to kill well. Remove tee. Well flowing back. Rig up pressure tool and lubricator. Lubricator leaks approximately 3/4 quart/minute. Run tool to 2,500 feet. 1,287.4 psi at 1421 pm. 1327 at 1440 pm. 1331 at 1504 pm. Leak developed in injection pipeline that feeds Well 1-A. Shut down 1-A at 1400. Well 5 shut down 1415. Well 4 at 1422. Rig up lubricator on No. 2. Well flowing back. Lubricator leaks. Wait on new lubricator and packing element from service company. Install lubricator and run pressure tool to 2,500 feet in Well No. 2.

9/20/83 - 12:44 am start injecting 0.7-0.8 BPM fresh water in No. 6. Pi=1,330 psi at 2,500 ft. Flowing pressure 1,750-1,805 psi; fluctuates. All other wells shut in. Rig up on Well No. 3; pull 1,230 feet of fiberglass tubing, tubing parted at threads, 41 joints removed.

9/21/83 - Shut in Well No. 6 at 12:21 am for falloff. Run tension packer on work string in No. 3. Set at 1,210, pressure up annulus, BOP, hoses, bradenhead leak. Pressure to 600 psi, packer leaks, water comes out top of work string. Weld bradenhead joint. Reset packer at 1,190, still leaks. Move packer and reset. Pressure up to 960 psi; 940 psi after 4 minutes. Pull string and replace tension packer with inflatible packer. Pressure to 250 psi, collar above bradenhead leaking. Shut in till AM. Continue to collect pressure data in No. 2 and No. 6 for falloff test.

9/22/83 - Remove pressure tools at 1:00 am from Wells 2 and 6. Well 3: Packer still at 1,200 ft. Pressure annulus to 1,055 psi. 15 minute stabilization period, start test at 1,038 psi; at end of one hour, pressure = 1,024 psi $\pm$ 2 psi (gauge had 20 psi increments) lost 14 psi. Break out tubing and packer. Go in for fish, tag it at 1,230. Screwed into fish, try to unseat inflatable packer at 2,712, won't release, string pulled loose, may have flared box on fish. Pull out of hole and lay down work string. Shut down till AM, wait on fishing tool.

9/23/83 - Well No. 3: Go in with overshot. Fluid flowing from annulus, other wells back on line. Grapple to fiberglass tubing. Fluid flowed from top of tubing, brine unloaded and then waste flowed back from tubing. Cap tubing, then pump in fresh water followed by brine. Go in hole with 2 perforating shots and collar locator tool. Shoot packer mandrel in center, pull shot carrier and logging tool. Pick up on string with 16,000 lbs. - won't come. Packer may not be deflated - wait till AM.

9/24/83 - Open surface valve on work string - flowed back into pit at approximately 40 gm through 1" hose. Rig up and pump 10 lb.

NaCl brine into tubing. Tubing pressure 440 psi; annulus pressure 340 while pumping. Stop pumping, flow back small amount of brine, well killed. Pull up on tubing with 16,000 lbs., won't come. Rig up tubing cutter, go in hole, tag packer. Pull up, shot won't fire. Pull out tool, screw had been damaged, cap open, charge got wet. Go in hole with new charge. Run to base of tubing. Shot misfired. Pull tool out. Shut down till AM.

9/25/83 - Go in hole with tubing cutter - Fire charge. Tubing free. Start out of hole, pulled 600 ft. of work string and well started to backflow into pit at increasing rate. Rig up pump and circulate brine into tubing and out of annulus. Pull remainder of work string with fish. Pull fiberglass string. Discoloration lessens downward from top fish. Connections very tight. Run caliper profile survey and gamma log.

8/26/83 - Go in hole with inflatable packer. Set packer at 2,334 ft. Annulus pressurized to 725 psi at 11:03 am. At 11:12, 698 psi; at 11:22, 690 psi; at 12:00, 620 psi. Bleed off pressure to 355; held for 12 minutes with no apparent change. (Gauge increments = 20 psi). Set packer at 2,339 ft. Held 10 minutes at 678 psi with no apparent change. Move packer to 2719. Pumped approximately 2-3 BPM at 450 psi. Move packer to 2626. Pumped same rate and pressure. Remove packer.

9/27/83 - Rig down on No. 3. Rig up on No. 2.

9/28/83 - Pump 9.9 lb/gallon brine into 7" casing of No. 2. Valve on opposite side of bradenhead has small leak. Attempt to weld leak, weld won't hold. Continue injecting brine to attempt to kill well so that bradenhead can be repaired. Pump 5,000 gallons brine; Bleed back pressure to <100 psi; Shut down till AM.

9/29/83 - Wellhead pressure zero psig. Go in hole with inflatable packer. Won't go past liner hanger at 1903. Pull out and run tubing to check TD. Run tubing to 2,850. Shutdown to wait for caliper log truck.

9/30/83 - Run caliper profile log in No. 2. Go in hole with smaller packer to 2,423. Pressure up annulus to 508 psi. After 35 minutes, 482 psi. Suggests slow leak, but indication that packoff at bradenhead may be leaking. Run packer to 2,500 feet pump fluid at approximately 1.9 gpm.

10/01/83 - 10/13/83: Not on site.

10/14/83 - Pumped brine into Well No. 1A to kill well.

10/15/83 - Pull fiberglass tubing, cutting anode wire free as tubing comes out - approximately 200 feet of anode wire left in hole. Pull all of fiberglass tubing and lay down. Go in hole with inflatable packer on work string.

10/16/83 - Finish running work string, tag obstruction at 2,722. Pull out of hole. Go in hole with open end work string to try to push cable down. Won't go past 2,300 feet (top of fiberglass casing) may be resting tangled on cable on top of collar. Pull out of hole.

10/17/83 - Go in hole with rope spear, pick up cable and pull out of hole. Go in with rope spear a second time, pick up more cable, pull out of hole. Go in third time, run down to open hole section, pull out - no cable. Run casing inspection caliper (40-arm) log.

10/18/83 - Go in hole with inflatable packer on work string. Annulus flowing into pit at approximately 2 - 3 gpm. Attempt to set packer at 2,781. Did not stop flow from annulus attempt to release packer. Can't pull up packer to reset. Packer appears to be set. Packer may be set due to differential pressure between tubing and work string. Attempt to pick up packer with 20,000 lbs. Won't come. Pump fresh water down (tubing?) annulus, follow with 10 lb. brine. Mix 10.4 lb. mud. Well killed.

10/19/83 - Packer free in AM. Set packer at 2,790 ft. Pumped into annulus at 52 rpm with triplex pump, 350 psi on casing head presure meter. Pump rated at 290 gpm/175 rpm, so rate = 86 gpm if 100% efficiency, 77 gpm if 90%, 69 gpm if 80%, 60 gpm if 70%. Unseat packer and move to 2,730. Pump into annulus at 30 rpm at 150 psi. Flow rate = 50 gpm (100%) - 35 (70%). Release packer, move to 2,273 into steel casing above DV tool. Pressure casing up to 1,010 psi, 1,000 psi after one hour. Tested ok. Bleed off pressure in tubing and casing till AM.

10/20/83 - Move packer to 2,320 ft. below D.V. tool pressure casing to 992 psi, 988 psi after one hour. Tested ok. Try to lower packer back into fiberglass casing - won't go. Pull packer out - can't shear ball - pull tubing wet.

10/21/83 - Set packer on workstring at 2,546 feet. Held pressure. Set at 2,606 feet. Pumped in one stroke/second (99 gpm to 69 gpm, depending on efficiency) at approximately 200 psi. Set packer at 2,591. Held pressure. Pull packer out of hole. Fill Mt. Simon zone with 100-mesh sand.

10/22/83 - Tag sand at 2780. Prepare for squeeze job. Pull out of hole and go in with packer with fiberglass tail pipe, 395 feet long. Set tail pipe 3 feet above sand. Pump 28 bbls. 10 lb./gallon brine, 1.5 BPM at 350 psi. Open tubing and circulate brine and mud into pit. Drop ball, set packer with 500 lbs. Packer at 2,378 feet. Attempt to shear ball - won't go. Release packer and POH, tubing wet. Repair swage (ball sheared but would not pass through swage). Run in and set packer same depth as before. Shear ball, pump in 15 bbls diesel followed by 14 BBL slurry of Epseal and silica flour. Displace with 5 BBLS Diesel. Shut down to wait on Epseal.

10/23/83 - 10/31/83: Not on site.

11/01/83 - Well No. 1A: Drilling on fiberglass tailpipe at 2,470. Penetration rate declined - may be junk in hole. Pull out mill and go in hole with magnet on sand line. Recover bits of wire (from fiberglass tubing collars?). Continue milling.

11/02/83 - Not on site.

11/03/83 - Well No. 3: Run tubing and packer to 2,150 ft. Pressurized annulus to 1,130 psi. Declined to 975 psi in 36 minutes. Pull tubing and packer. Prepare for cementing.

11/04/83 - Well No. 3: Make up hastelloy casing with built-in polished bore receptacle, hastelloy blank section, cement shoe, and cementing seal assembly. Attach to 5" OD steel casing - run from 2,805 to surface and prepare for cementing. Mix Epseal and silica flour. Begin pumping cement Pozmix, then diesel fuel, then Epseal, drop wiper plug, displace with diesel, then water, bump plug, shut down to wait on cement.

11/05/83 - Well No. 1A: Drilled out Epseal to 2,800 feet. Go in hole with packer to test casing. Pressure casing to 500 psi. Fell to 400 psi in 3 minutes. Repressurize with two strokes of pump - approximately three gallons - leak rate estimated to be approximately one gpm. Release packer and repeat above test at 2,760, 2,712, 2,633 with same results. Casing holds at 2,575. Leak apparently in same area that was squeezed.

11/06/83 - Well No. 3: Test entire casing. Pressurize casing to 1,245 psi, fell to 1,239 in 6 minutes. Remained unchanged at 1,239 psi for the next 54 minutes. Casing apparently has no leaks.

Well No. 1A: Go in hole with open-ended work string to 2776. Balance pozmix cement from 2776 to 2340. Pull out five stands of work string, squeeze cement from surface.

11/07/83 - Well No. 3: Rig down for repairs.

Well No. 1A: Drilled out cement. Test with packer as before, leaking in same area at approximately same rate.

11/08/83 - Well No. 1A: Squeeze leaking zone with Class A cement with $CaCl_2$.

11/09/83 - Well No. 1A: Drilling on cement.

11/10/83 - Well No. 1A: Cement drilled out to 2,630 feet. Pull one stand tubing to pressure test against cement. Pressure casing to 555 psi. Fell to 465 psi in 21 minutes. Change presure gauges. Pressure casing to 505 psi - fell to 456 psi in 12 minutes. Again pressure casing, to 505 psi - fell to 325 psi in 1 hour, 5 minutes. Prepare to drill out cement.

11/11/83 - Drilled out cement in Well 1A. Install tubing and packer at 2770. Pressure to 510 psi - fell to 490 psi in 6 minutes.

11/12/83 - Well No. 5: Rig up. Pump 9.8 lb. brine to kill well.

Well No. 1A: Begin milling out fiberglass casing.

Well No. 3: Complete engine repairs.

11/13/83 - Well No. 5: Pull fiberglass tubing.

Well No. 1A: Milling fiberglass casing.

Well No. 3: Drilling out cement shoe.

11/14/83 - Well No. 5: Pull packer and polished bore receptacle assembly.

Well No. 3: Drilled through cement shoe. Circulate formation clean. Spot acid in formation.

Well No. 1A: Milling fiberglass casing. Begin reaming Mt. Simon interval.

11/15/83 - Well No. 5: Set packer on work string at 2780. Attempt to set packer - won't set. Pull packer out of hole-element ruptured. Redress packer.

Well No. 3: Pump in acid, followed by 50 bbls fresh water, at 700 psi and approximately 20 gpm. Rig up RA tracer tools. Conduct background gamma log from 2,200 ft. to TD, 2,906 KB. Start pumping fresh water down casing at 700 psi and 20 gpm. Lubricator leaking. Shut down to repair lubricator.

Well No. 1: Milling on fiberglass casing.

11/16/83 - Well No. 3: Go in hole with RA tracer tools. Conduct background gamma log from 2,200 ft. to 2,906 KB. Start pumping fresh water down casing at 700 psi. Release radioactive tracer. Gamma tool not working. Displace tracer with 60 bbls fresh water and remove faulty gamma tool to repair. Go in hole with RA tracer tools. Release tracer at 2,200 ft. while pumping 1/3 bpm. Make log from TD to 2,200. Fluid going away near base of Mt. Simon.

11/17/83 - Well No. 5: Run 40-arm caliper tool to 2,740; open tool, pull up to find top of Inconel casing - tool not open. Lower tool to 2,786 - attempt to open. No results - pull out of hole. Tool ran successfully on second attempt.

Well No. 3: Install 40 jts fiberglass tubing.

11/18/83 - Well No. 5: Packer set at 2,700 feet. Pressure casing to 770 psi - bleed off at 5 psi/minute. Wellhead may be leaking.

Well No. 3: Finish installing fiberglass tubing - centralizes on tailpipe won't go through milled-out cement shoe. Pull tubing out of hole and cut mule shoe end on centralizer. Start installing tubing.

11/19/83 - Well No. 5: Weld wellhead. Set packer at 2,700 feet. Pressure to 1,000 psi - fell to 550 immediately, then fell slowly to 500 psi in 15 minutes. Rig mud pump difficult to control for small flow rate. Move packer to 1,260 feet. Pressure casing - won't hold 1,000 psi - falls to 582 psi and holds steady at that pressure.

Well No. 3: Finish installing tubing. Locate seal assembly - close hydrill pack-off at surface to pressure test.

11/20/83 - Well No. 5: Set packer at following depths - 480, 540, 782, 902, 1,145, & 1,135 - got slow bleed off each place.

11/21/83 - Well No. 5: Set packer at following depths - 1,205, 1,250,. 1,266, & 1,295 - got slow bleed of each place. Attempt to get pump-in rate - 500 psi back pressure - regardless of rate Formation breaking down.

11/22/83 - 11/23/83: Not on site.

11/24/83 - Well No. 5: Set retrievable inflatable packer at 2,768 feet. Set second packer on drill pipe at 1,290 feet. Pressurize upper annulus to 690 psi. Pressurize tubing and packed-off zone to 990 psi - fell to 925 psi in 22 min. but gauge apears to be leaking. Replace gauge and bleed air from tubing. Repressure packed-off interval to 982 psi. Fell to 906 psi in 15 minutes and 860 psi in 65 minutes. Pull upper packer out of hole.

Well No. 1A: Drop sand in Mt. Simon interval to prepare to cement liner with lower hastelloy section with built-in polished bore receptacle.

11/23/83 - Well No. 5: Bottom packer at 2,768. Top packer moved to 2,406 feet. Pressure casing to 640 psi. Pressurize tubing and packed-off zone to 950 psi - fell to 735 psi in 15 minutes.

Well No. 4: Rig up.

11/24/83 - 11/25/83: Not on site.

11/26/83 - Well No. 5: Rig down.

Well No. 1A: Install liner and prepare for cementing.

Well No. 4: Rig up.

11/27/83 - Well No. 6: Rig up.

Well No. 1A: Cement liner. Pump diesel, followed by Epseal at 2 bpm and 1,700 psi. Got good returns throughout.

Well No. 4: Pull tubing. Lower 400 ft. of tubing discolored.

11/28/83 - Well No. 1A: Waiting on cement.

Well No. 6: Kill well with brine.

Well No. 4: Locate packer on workstring at 2,780 feet.

Pump fluid into annulus at 22 strokes/minute = 70-80 gpm at 175 psi. Move packer to 2,656 and get same results. Move packer to 2,594 and pressure to 513 psi - fell slowly to 442 psi in 45 minutes.

11/29/83 - Well No. 4: Run caliper, gamma, and casing inspection logs.

11/30/83 - Well No. 4: Packer set at 2,333 on workstring. Pumped 1/4 bpm at 700-750 psi into casing. Fell immediately to 608 psi when pumping stopped. Probable hole opposite low-permeability formation.

Well No. 1A: Pressure tested casing and new liner. Three tests: First test fell from 1,010 psi to 947 psi in 108 minutes; second test fell from 1,010 psi to 960 psi in 65 minutes; third test increased pressure to 625 psi and held for 10 minutes - fell to 615 psi. Increased to 705 psi and held for 10 minutes - fell to 700 psi. Increased to 810 psi and held for 10 minutes - fell to 806 psi. Increased to 911 psi and held for 10 minutes - fell to 906 psi. Increased to

1,010 psi - fell to 1,002 psi in 15 minutes and 980 psi in one hour and 15 minutes.

Well No. 6: Removed fiberglass tubing. Start in hole with packer retrieving tool.

Well No. 4: Moved packer to 2,783. Pump into casing (through probable leak) at 89 gpm at 100 psi surface pressure. Blow shear ball and pump into tubing (into Mt. Simon Formation) at 44 gpm at 100 psi surface pressure.

12/01/83 - Well No. 3: Started pumping fresh water at 1:00 pm. Shut down to fix small drip at wellhead. Started again 3:15 pm. Bring well up to 35 gpm at 600 psi.

Well No. 6: Retrieve packer/polished bore assembly and start in hole with inflatable packer.

Well No. 1A: Milling casing shoe.

12/02/83 - Well No. 3: Flow rate 40 gpm at 650 psi at 8:15 am. Level of annular fluid reservoir (seal pot) has not changed more than one inch since well started. Seal pot pressure = 995 psi.

Well No. 6: Set packer at 2,770 feet. Pump brine into casing at approximately 60 gpm at 150 psi. Disconnect flow line from casing and connect to work pipe. Shear pin at 1,000 psi. Pump for brief period at same rate and approximately 400 psi. Just as the pump was stopped, brine started flowing from the blow-out preventer. May be channeling by packer. Remove packer and run logs.

Well No. 1A: Milling on junk in open-hole section.

12/03/83 - Well No. 3: Flow rate 37 gpm and injection pressure 690 psi at 10:30 am. Oil level in seal pot still same. 1,010 psi on seal pot.

Well No. 6: Packer set at 2,600 feet. Bubbles observed coming around casing (pool of water at ground surface around casing). Possible trapped air below water. Pressure inside casing raised to 975 psi. Bled off slowly to 820 psi in 5.5 minutes. Leak observed at BOP flange. Attempt to tighten. Stopped due to risk of bending casing. Raise casing pressure to 472 psi. Held 15 minutes with no loss of pressure - Rig down.

12/04/83 - Well No. 1A: Milling on junk.

Well No. 3: Flow rate 35 gpm and injection pressure 700 psi. 1,020 psi on seal pot. Oil level stable.

12/05/83 - 12/19/83: Not on site.

12/20/83 - Well No. 4: Cement steel casing with Hastelloy lower section with built-in polished bore receptacle. Lost circulation just after pad returned to surface. Cement should be within 100-300 feet of surface.

12/21/83 - 1/03/84: Not on site.

1/04/84 - Well No. 4: Prepare to run fracturing test - clean and circulate hole. Cut notch ten feet long at formation face at base of Mt. Simon.

1/05/84 - Well No. 4: Run background gamma log. Go in hole with tracer material. Begin pumping one bpm. Raise pressure and flow rate in increments of approximately 200 psi. Reach 1,600 psi. No indication that formation parted. Gamma tool shows that bulk of fluid is entering notched area. Decide not to frac. well.

1/06/84 - Clean out hole in order to run RA tracer test.

1/07/84 - 1/09/84: Not on site. RA tracer test run 1/09/84.

Appendix B

APPENDIX B

Pressure Falloff Trends

at CWM Injection Wells

## PRESSURE FALLOFF TRENDS

During testing of the injection wells in the fall of 1983, wells were taken out of service at different times for testing or maintenance. Normal operational measurement of tubing head pressures continued during these periods of well shut in. These data have been plotted against log shut-in time ("MDH plot") on the figures presented on the following pages. Note that the fluid in the wells was fresh water in some cases and brine or waste in others. The trends are rather "bumpy" since the gauges are marked in 20-psi increments. These plots were analyzed for flow capacity of the receiving formation, which is proportional to the slope of the straight line on these plots. The method of analysis is based on the solution to the problem of transient radial flow from or to a line source in a homogeneous, isotropic, confined reservoir of infinite areal extent (Theis, 1935). The slope of the best-fit straight line was determined and used in the following equation:

$$Kh = 162.6 \frac{Q}{\Delta p}$$

Where:

$K$ = permeabilty (md)

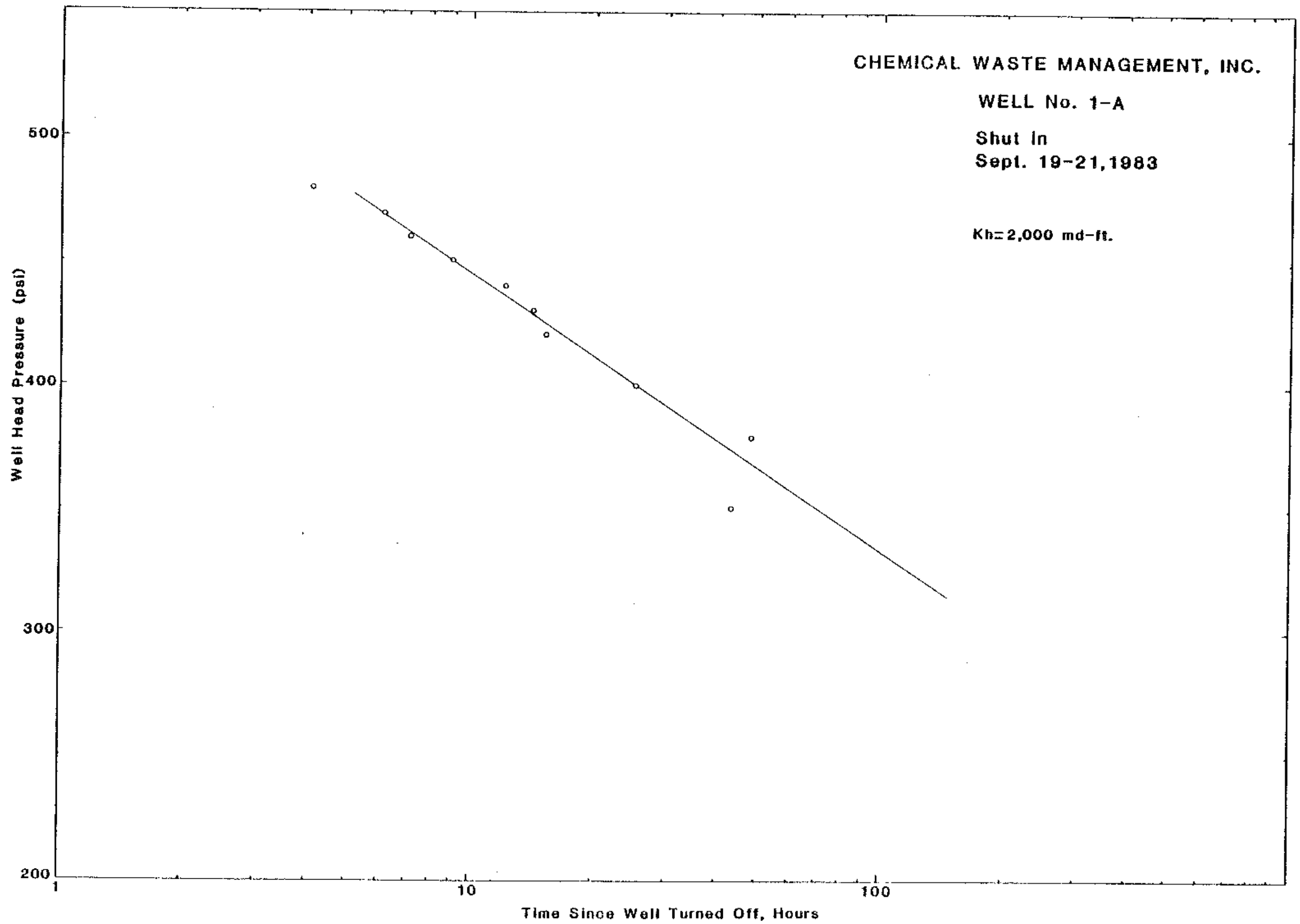
$h$ = formation thickness (ft.)

$Q$ = flow rate (bbls/day)

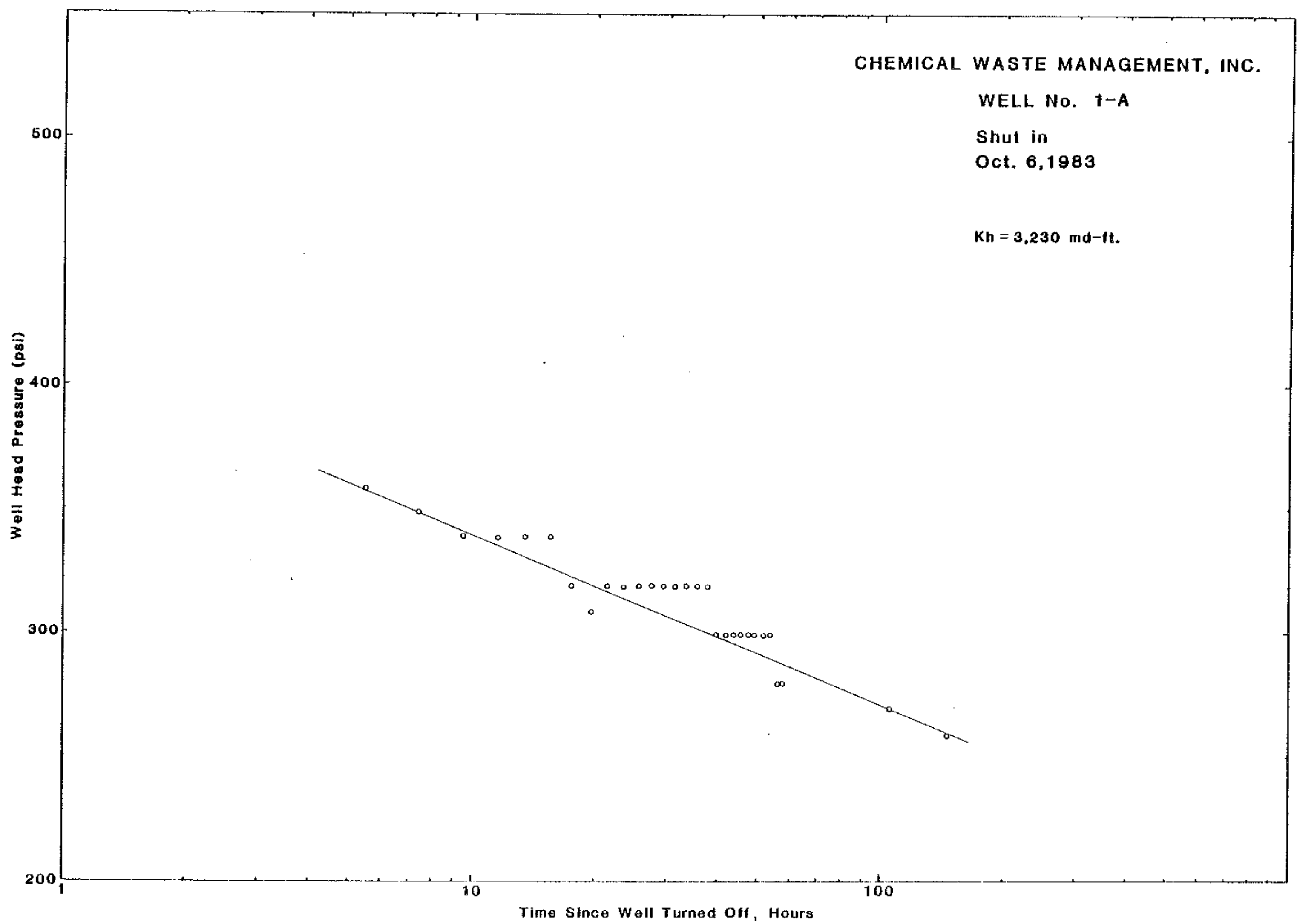
$\Delta p$ = change in pressure over one log cycle (viscosity assumed to be 1.0 cp)

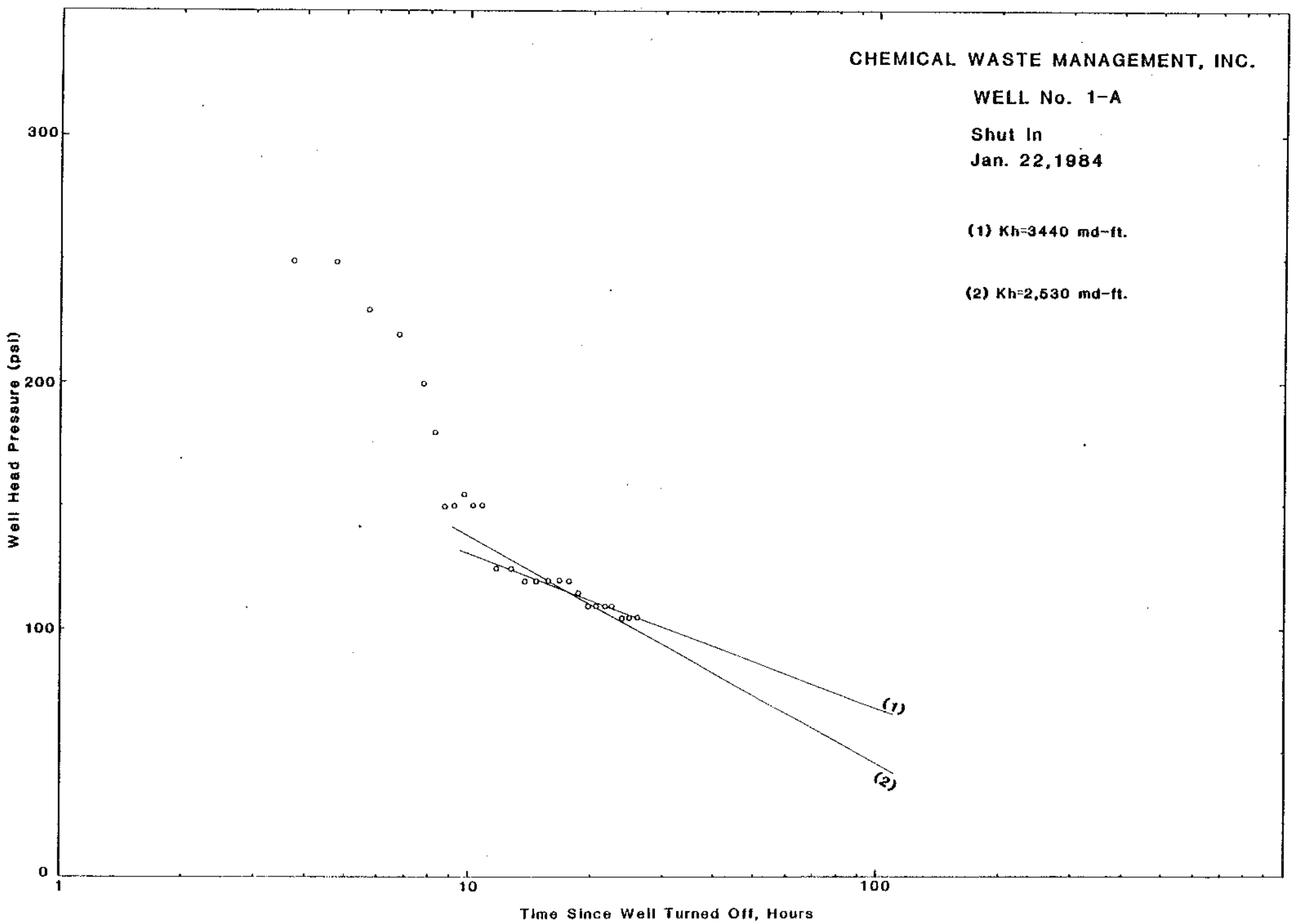
It was assumed that the wells were far enough apart so that the pressure disturbance due to continued injection or shut-in of a neighboring well did not affect the falloff trends. The calculated values of flow efficiency are shown on the plots and discussed in Section 6.2.5.

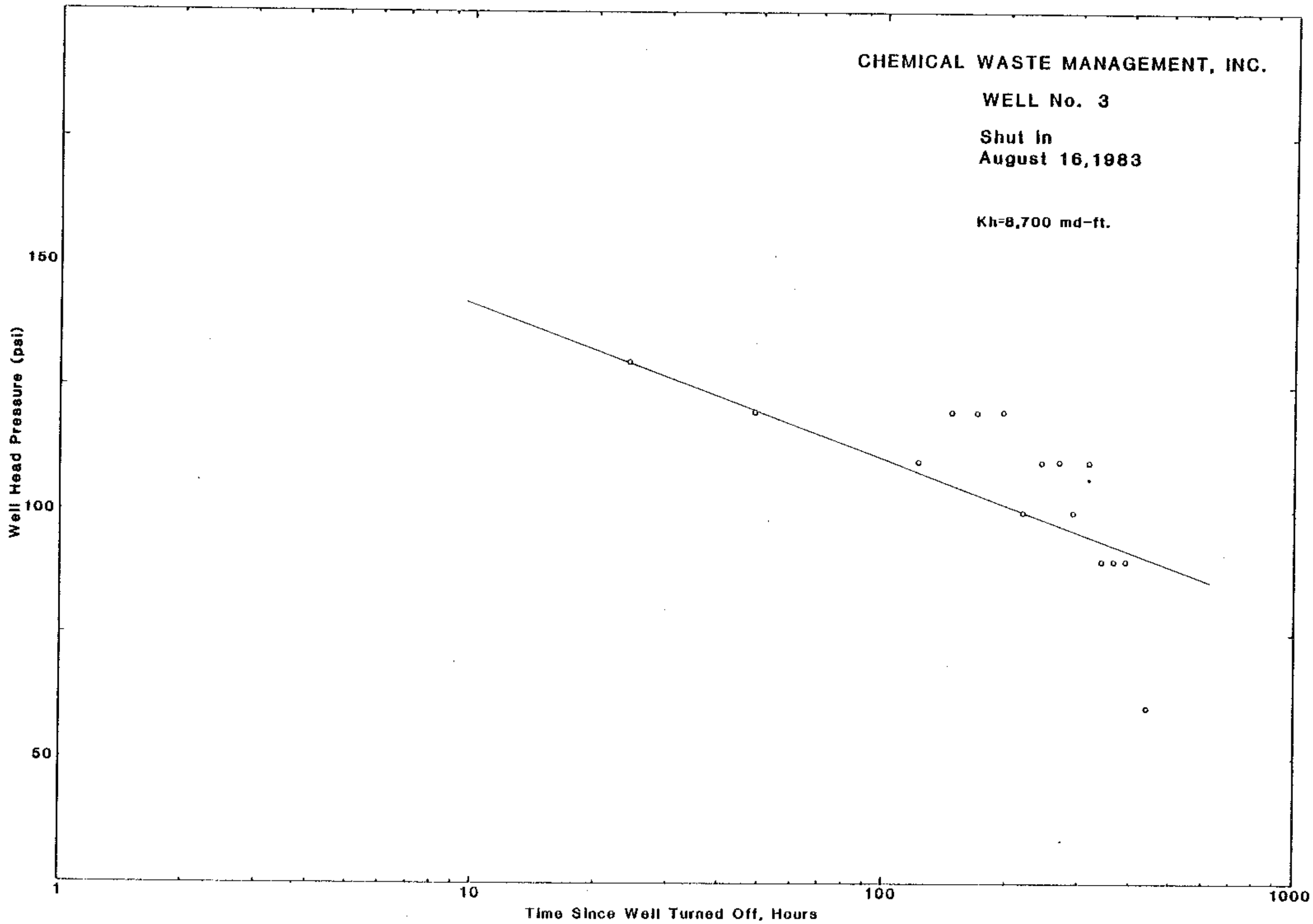
While this work was underway, it became apparent that the wells were leaking into zones other than the Mt. Simon Formation. The calculated values of flow capacity in many of these cases, therefore, represents part or all of the Mt. Simon plus part or all of the beds into which fluid was leaking. The points of fluid exit were located inside the wells, but the portion of total formation thickness into which flow actually occurred is not known. Although the values of flow capacity are valid, it is not known with certainty to which stratigraphic zones these values apply. Other values were derived from wells which had been recompleted so that the wells were open only to the Mt. Simon Formation (Wells 1A and 3 in January, 1984).

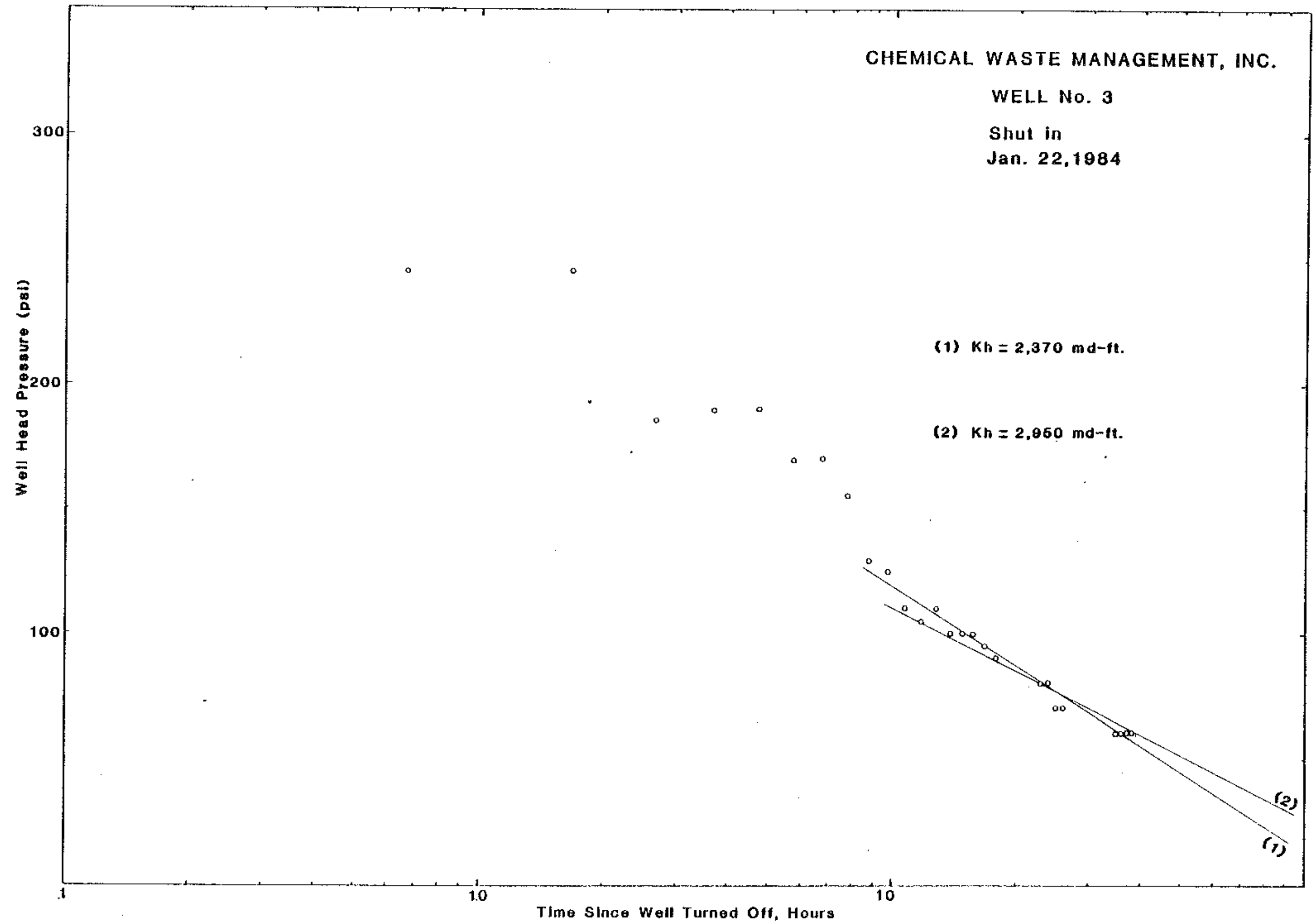


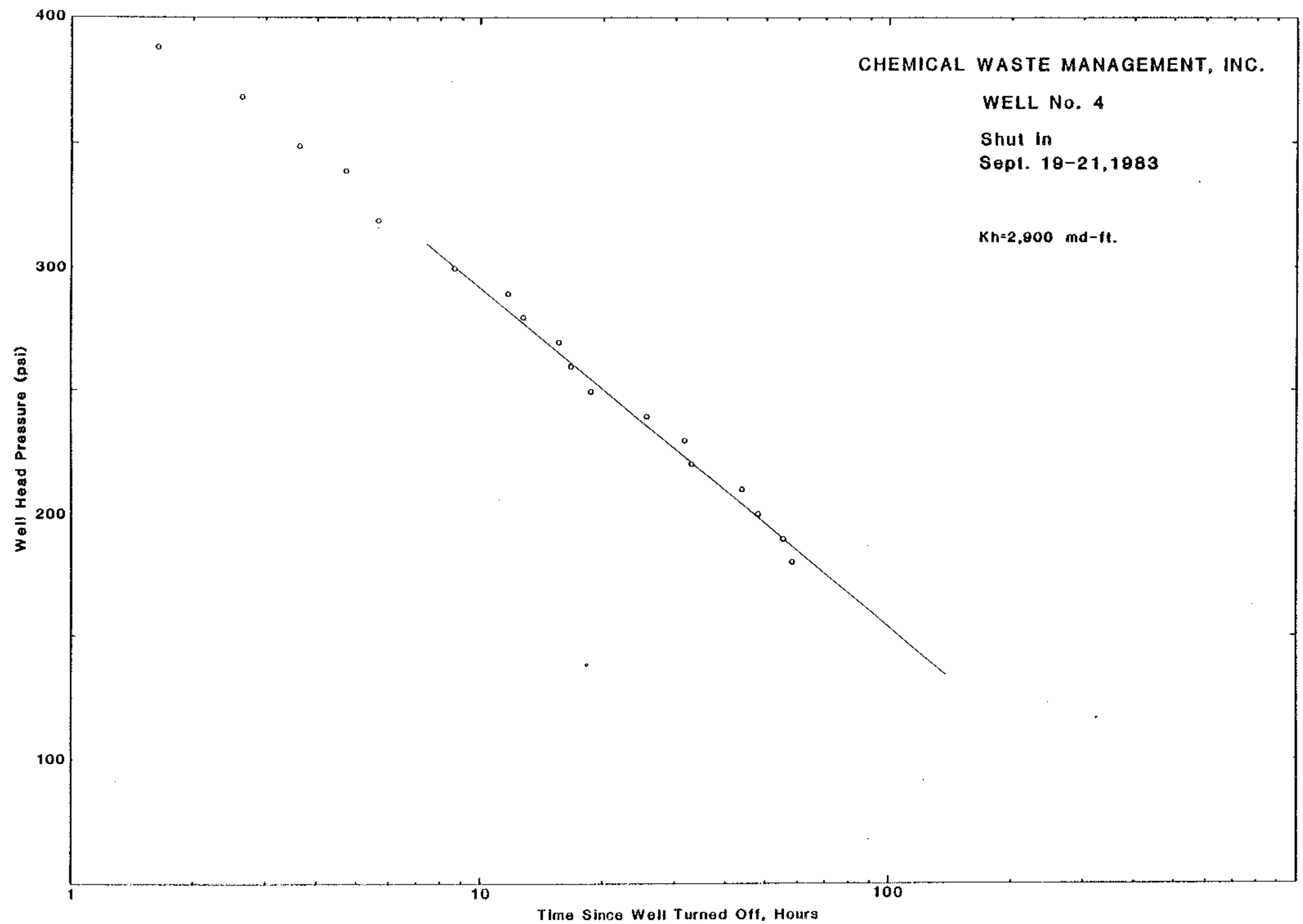
CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 1-A
Shut In
Sept. 19-21,1983
Kh=2,000 md-ft.
500
400
300
200
Well Head Pressure (psi)
1
10
100
Time Since Well Turned Off, Hours

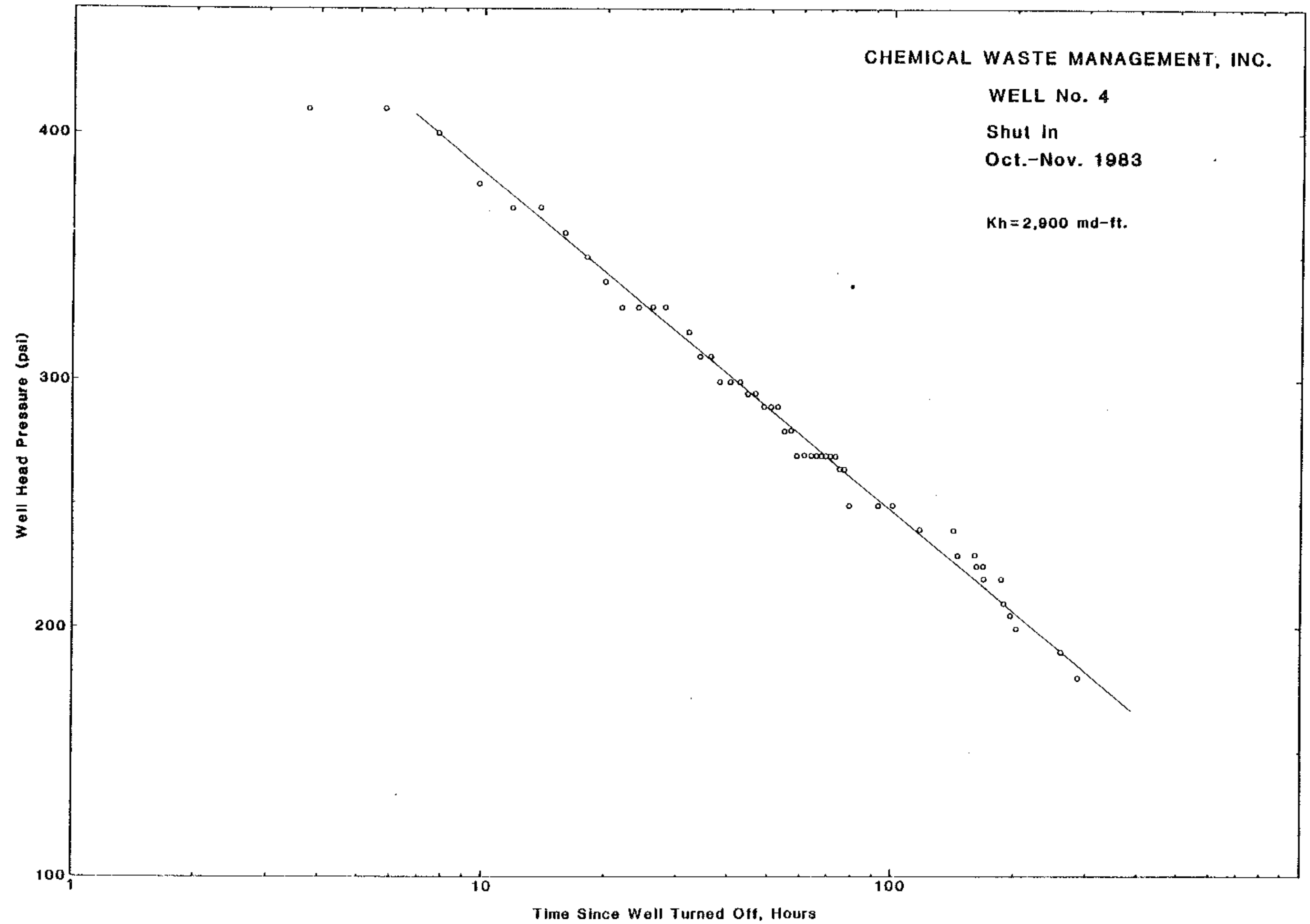

CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 1-A
Shut in
Oct. 6,1983
Kh = 3,230 md-ft.
Well Head Pressure (psi)
500
400
300
200
1
10
100
Time Since Well Turned Off, Hours

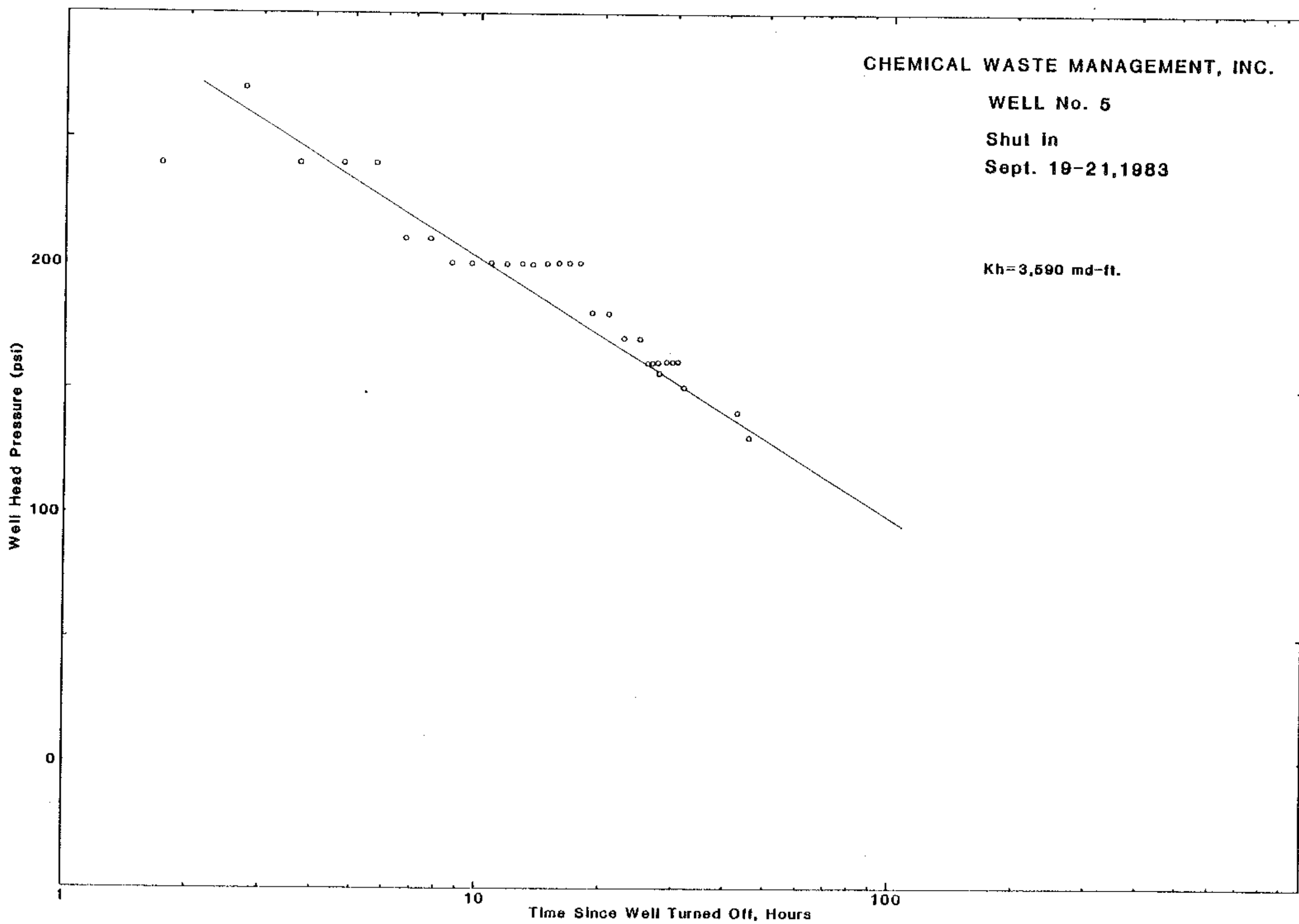

CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 1-A
Shut In
Jan. 22,1984
(1) Kh=3440 md-ft.
(2) Kh=2,530 md-ft.
300
200
100
0
Well Head Pressure (psi)
1
10
100
Time Since Well Turned Off, Hours
(1)
(2)


CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 3
Shut In
August 16,1983
Kh=8,700 md-ft.
150
100
50
Well Head Pressure (psi)
1
10
100
1000
Time Since Well Turned Off, Hours

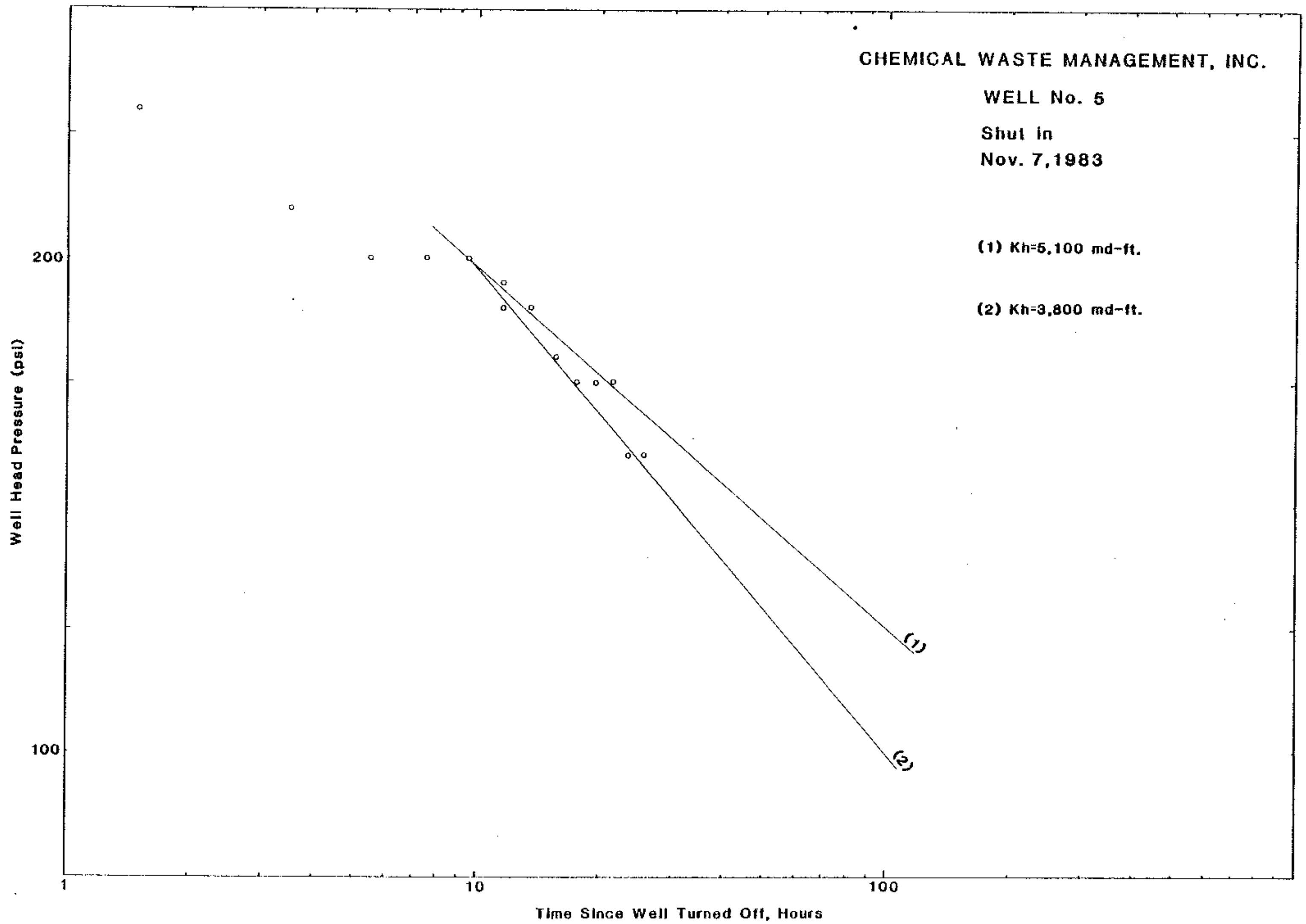

CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 3
Shut in
Jan. 22,1984
(1) Kh = 2,370 md-ft.
(2) Kh = 2,950 md-ft.
300
200
100
Well Head Pressure (psi)
.1
1.0
10
Time Since Well Turned Off, Hours
(1)
(2)


CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 4
Shut In
Sept. 19-21,1983
Kh=2,900 md-ft.
400
300
200
100
1
10
100
Well Head Pressure (psi)
Time Since Well Turned Off, Hours

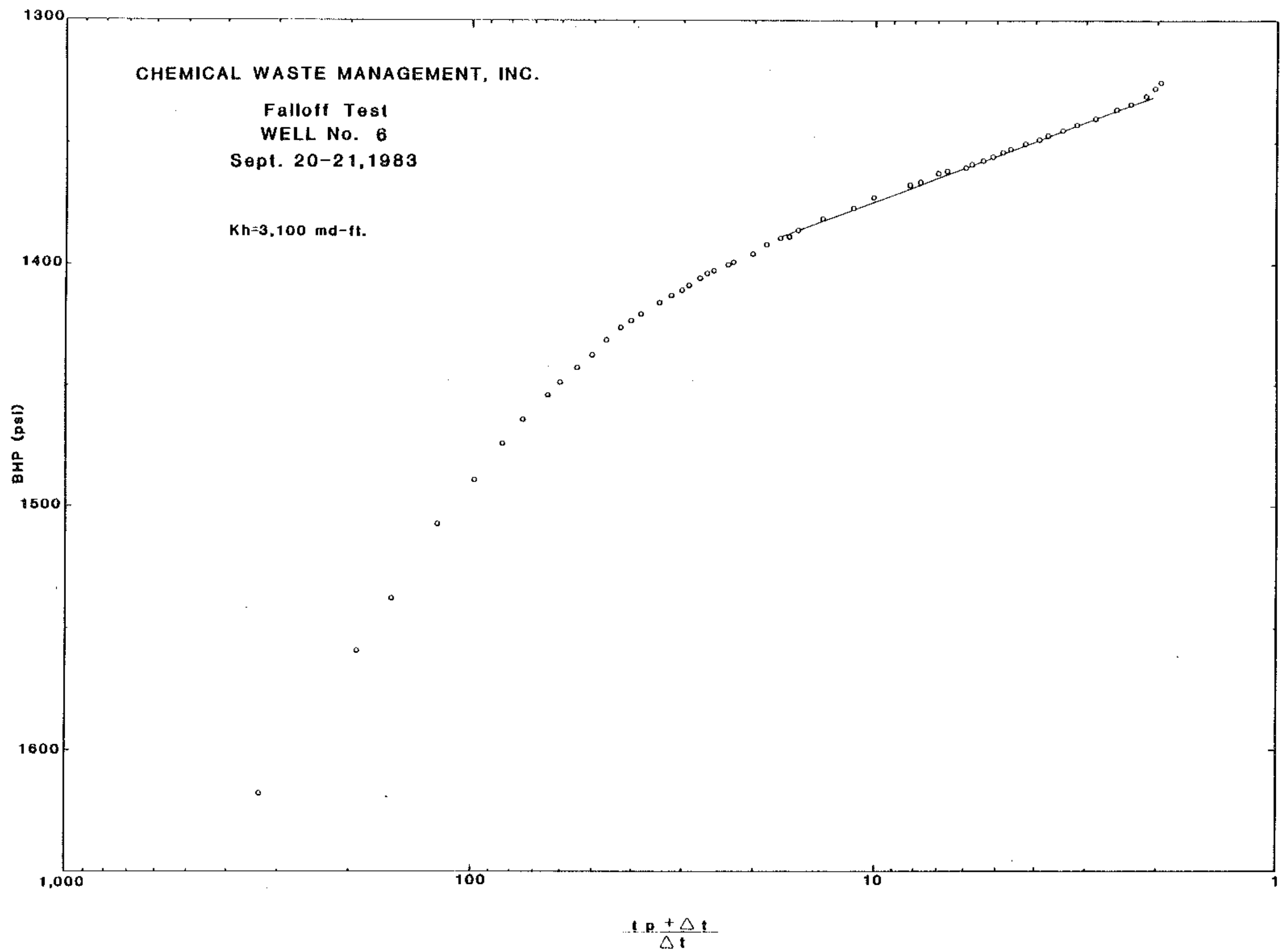

CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 4
Shut In
Oct.-Nov. 1983
Kh=2,900 md-ft.
400
300
200
100
1
10
100
Well Head Pressure (psi)
Time Since Well Turned Off, Hours

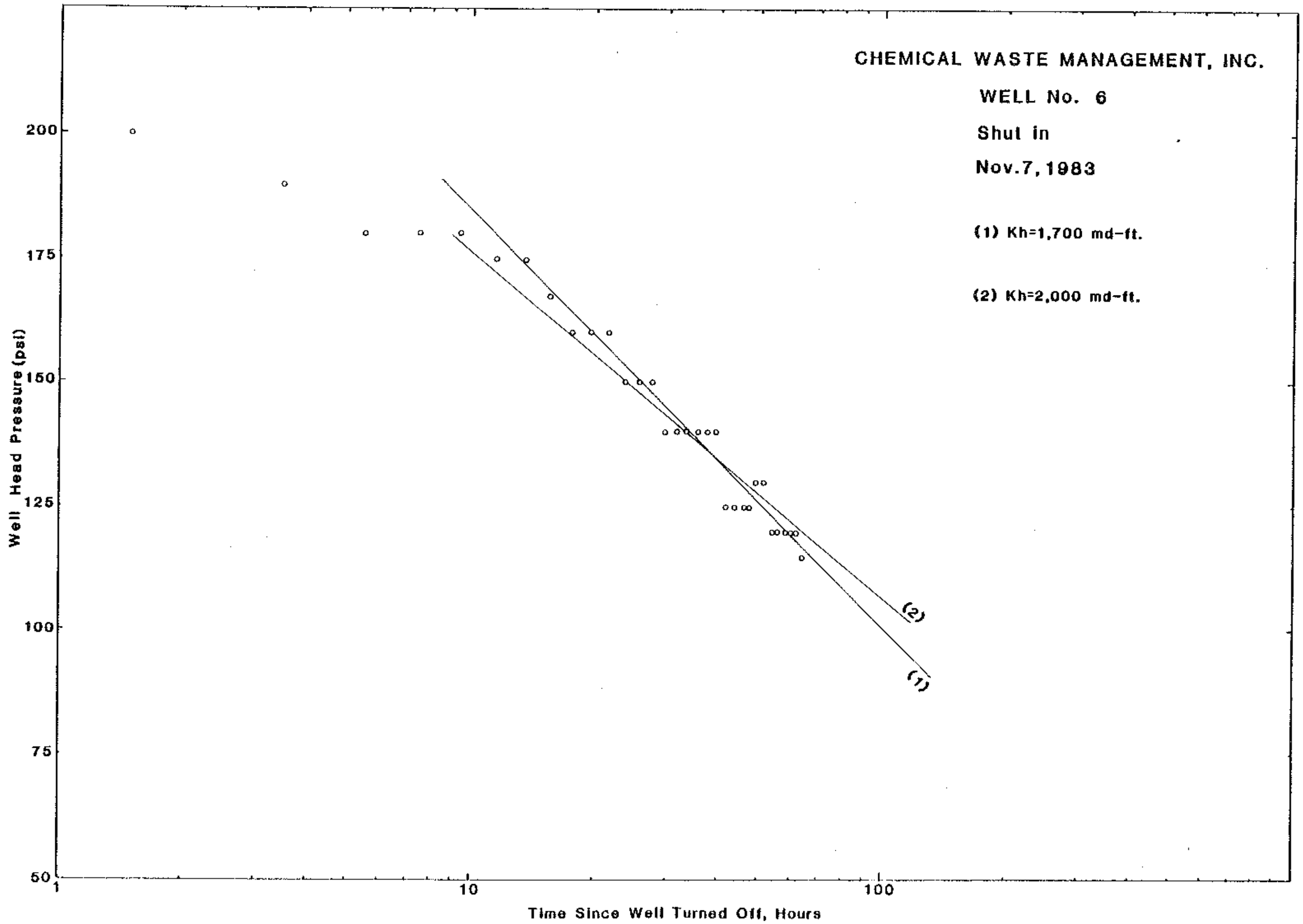


CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 5
Shut In
Sept. 19-21,1983
Kh=3,590 md-ft.
Well Head Pressure (psi)
200
100
0
1
10
100
Time Since Well Turned Off, Hours



CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 5
Shut In
Nov. 7,1983
(1) Kh=5,100 md-ft.
(2) Kh=3,800 md-ft.
200
100
Well Head Pressure (psi)
1
10
100
Time Since Well Turned Off, Hours
(1)
(2)


CHEMICAL WASTE MANAGEMENT, INC.
Falloff Test
WELL No. 6
Sept. 20-21,1983
Kh=3,100 md-ft.
1300
1400
1500
1600
BHP (psi)
1,000
100
10
1
$\frac{t_p + \Delta t}{\Delta t}$



CHEMICAL WASTE MANAGEMENT, INC.
WELL No. 6
Shut in
Nov.7,1983
(1) Kh=1,700 md-ft.
(2) Kh=2,000 md-ft.
Well Head Pressure (psi)
200
175
150
125
100
75
50
1
10
100
Time Since Well Turned Off, Hours
(1)
(2)